



ARKANSAS
Department of Environmental Quality

OCT 01 2007

Chuck Hammock
Environmental Manager
Lion Oil Company
1000 McHenry Drive
El Dorado, AR 71730

Dear Mr. Hammock:

The enclosed Permit Number 0868-AOP-R5 is issued pursuant to the Arkansas Operating Permit Program, Regulation # 26.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. for the construction, operation and maintenance of an air pollution control system for Lion Oil Company to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under §2.1.14 of Regulation No. 8, Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, within thirty (30) days after service of this decision.

All persons submitting written comments during this thirty (30) day period, and all other persons entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Director should be reversed or modified. Such a request shall be in the form and manner required by §2.1.14 of Regulation No. 8.

Sincerely,

A handwritten signature in cursive script, appearing to read "Mike Bates".

Mike Bates
Chief, Air Division

5005 1 0 100

RESPONSE TO COMMENTS

Lion Oil Co.

AFIN#: 70-00016

Permit #: 868-AOP-R5

On July 20, 2007, the Director of the Arkansas Department of Environmental Quality gave notice of a draft permitting decision for the above referenced facility. During the comment period, one interested party submitted written comments, data, views, or arguments on the draft permitting decision. The Department's response to these issues is as follows:

Comment #1: Page 8 of 22, Section 11. CALCULATION: It states, "The facility used 1995 AP-42 factors for NO_x on the combustion sources and a HHV of 1000 BTU/scf factor. This was different than the 1998 AP-42 factors and HHV factor that was used for VOC, CO, and PM/PM₁₀."

Pursuant to 40 CFR 60.14(b)(1), Lion is required to use emission factors from the latest version of AP-42. Please explain and justify the use of 1995 AP-42 emission factor for NO_x instead of the newer 1998 AP-42 factor.

Response #1: The referenced section pertains to NSPS modifications. As stated in the referenced section, modified sources shall determine their emission rate based upon the latest AP-42 factors or "other emission factors determined by the Administrator to be superior to AP-42 emission factors." The sources being modified in this revision use NO_x emission factors based upon manufacturer's specifications and testing. The commentator is referring to a notation in the Statement of Basis which does not apply to NSPS sources subject to any modification in this revision.

Comment #2: Page 11 – 22, Table 3 – Table 7: Please give Source Number (SN) after Source Description for easy identification.

Response #2: The source numbers have been added to Tables 3 through 7 for easy identification as requested.

Comment #3: Page 11, Table 3: The description of SN-805N is stated as "New No. 4 Vacuum Furnace" (See the 5th paragraph of Page 10) and as "New No. 4 Atmospheric Furnace" (Table 3 of Page 11). Please be consistent with the description.

Response #3: SN-805N is designated as the New No. 4 Vacuum Furnace. This comment refers to a typographical error in the permit and has been corrected.

Comment #4: Page 26, 5th paragraph: It states, "SN-803 and SN-804 are not subject to BACT for NO_x and CO because these sources are being replaced with new generation ultra-low NO_x burners (NGULNB) before the refinery expansion will come on line, and thus, will experience decreases in NO_x and CO."

*The increase in NOx emissions from the 2003/2004 baseline as a result of the proposed expansion is significant and therefore PSD analyses requiring BACT and air quality impact for NOx is required. We are aware that Lion Oil is required by the Consent Decree (CD) to reduce NOx emissions for some emission sources. The requirements in CD **cannot** be considered as BACT nor do they supersede the SIP PSD permit regulations. Therefore all the emission sources (SN-803 and SN-804) that are physically modified must have a BACT analyses for CO and NOx.*

Response #4: This comment refers, in part, to a typographical error. The permit should state that SN-803 and SN-805 are experiencing a decrease in NO_x, not SN-803 and SN-804. Under the Federal Prevention of Significant (PSD) rules contained in Title 40 of the Code of Federal Regulations Part (40 CFR) 52.21(j), each new major source and/or major modification must employ Best Available Control Technology (BACT) for each pollutant for which the new source or modification is considered major. However, per 40 CFR 52.21(j)(3), a BACT analysis is only required for an emissions unit if the emissions unit also experiences a net emissions increase.

40 CFR 52.21(j)

(3) A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. (emphasis added)

Since these two heaters will be retrofitted with next generation Ultra Low-NO_x burners (NGULNB) as part of the Expansion Project, SN-803 and SN-805 will not experience an increase in actual NO_x emissions (they will experience a decrease) and, therefore, are not subject to BACT.

Comment #5: *Page 32, 2nd paragraph: It states, "The proposed CO BACT is high temperature regeneration and a proposed FCCU short-term flue gas emission limit consistent with the NSPS limit and Consent Decree limits of 500 ppm_{dv} and a 365-day rolling average limit of 100 ppm_{dv}."*

Lion should do a top down BACT analysis for CO emissions. The proposed CO BACT limit, which is consistent with the NSPS limit and Consent Decree, does not meet the criteria of BACT because "BACT limit should be nearly always be more stringent than NSPS". EPA addressed this issue in letter to Mr. Richard Grusnick of Alabama Department of Environmental Management on July 28, 1987.

Response #5: A top down BACT analysis was completed for CO emissions from the FCCU. It is on page 6-12 of the application. The proposed CO BACT limits of 500 ppm_{dv} and 100 ppm_{dv} (365-day average) are comparable to the most stringent limits listed in

the RBLC for similar controls at the time the application was submitted. Lower limits in the RBLC are for partial burn FCC units with CO boilers. The Williams Refining & Marketing (Memphis Refinery) RBLC entry of 50 ppm CO is incorrect. The Memphis Refinery, now owned by Valero as part of the Premcor Refining Group, has an FCCU CO BACT limit of 300 ppm_{dv} on a 3-hour average (as well as the NSPS J limit of 500 ppm_{dv}).

Comment #6: Page 32, Item 5. BACT Analysis for #9 Cooling Tower, SN-853-9: It states, "The emission rates estimated for the new cooling tower are consistent with those listed in the RBLC. The only drift elimination was a single entry of 0.005%. The facility has chosen drift eliminators as control with drift of 0.008%."

Since Lion has selected the same control technology referenced in RBLC, please explain why 0.005% is not achievable. Lion should provide EPA with the top down BACT analyses and its rationale for determining BACT emission limits.

Response #6: After reviewing specifications for cooling tower drift eliminators, Lion agrees that 0.005% drift is achievable. Updated emissions estimates for the affected cooling towers are 1.5 lb/hr and 6.6 tpy particulate.

*Comment #7: Page 33, 2nd paragraph: It states, "The Pre-flash Column Reboiler (SN-803) is a NSPS **Subpart J quality gas** fired furnace... Bottoms from the column are heated in the **fuel gas** fired Atmospheric Topping Furnace (SN-804) prior to distillation at atmospheric pressure." (Emphasized in bold)*

"Subpart J quality gas" is not a defined term in 40 CFR Part 60, neither are several other terms (refinery fuel gas, natural gas, and gaseous fuel) about gas fuel. 40 CFR Part 60, Subpart J has the definition of "fuel gas" as indicated below.

"Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners." (40 CFR §60.101)

If these terms convey the same meaning, please select one term to be used throughout the draft permit; otherwise, please define the term before using it and provide specific Federal and State regulations that apply to that specific term.

Response #7: "NSPS Subpart J quality gas" and "refinery fuel gas" have been defined in Plantwide Condition 11(a). The term "gaseous fuel" has been replaced with "refinery gas fuel."

Comment #8: Page 77, Specific Condition 12: It states, "The #10 Furnace/Reboiler (SN-813a), Naphtha Splitter Reboiler Heater (SN-857)...are subject to and shall comply with all applicable provisions of 40 CFR Part 63 Subpart DDDDD – National Emission Standard for hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process heaters." (Boiler MACT)

On July 31, 2007, District of Columbia Court of Appeals vacated the Boiler MACT regulations with no stay. Therefore, the requirements of Section 112(j) of the Clean Air Act (case-by-case MACT) provisions apply to Industrial Boilers, Process Heaters, and Commercial Boilers.

Lion should submit an application to obtain source-specific case-by-case MACT according to Federal Regulations 40 CFR 63.52. Conditions of the MACT determination must be incorporated in the Title V operating permit.

Section 112(j) MACT determinations can be made either through the Title V permitting process or State permitting authority may work with a new affected source to do a Notice of MACT approval during the preconstruction process. Either way, the determination issued by a State would have to undergo public comment (and opportunity for public hearing) and be sent to EPA Region for review. Information on the 112(j) rulemaking is available on EPA's website.

Response #8: The Department is aware of the vacatur of Subpart DDDDD and we have removed all conditions required by this subpart which are not required for compliance with any other emission standard (see our response to comment 28).

Regarding the applicability of Section 112(j), this Department considers this a separate issue unrelated to issuance of the permit at hand. The Department has been waiting for guidance from the EPA on 112(j) applicability to all of Subpart DDDDD sources in Arkansas. While Section 112(j) may apply in the void created by the vacatur of Subpart DDDDD, we find no basis in National program guidance to support its applicability in this instance.

The ADEQ stands ready to fulfill our obligations under Section 112(j) regarding Industrial Boilers, Process Heaters, and Commercial Boilers; however, at this time we are unsure what those obligations are. Once the situation is clarified, we will take the appropriate steps.

Comment #9: *Page 87, Specific Condition #63: It states, "The permittee shall demonstrate through an initial test CO emission rates no greater than 0.0625 lb/MMBTU at SN-805 and 0.0495 lb/MMBTU at SN-803 to demonstrate that an actual decrease in actual emissions occurred and thus, exempting the source from BACT for CO. The initial test shall take place 180 days after retrofit of these sources."*

Please explain where those limits were derived. These limits aren't found in Table 12 – Subpart J Units Criteria Emissions (page 72 – 74), or given any explanation. Lion should demonstrate why it cannot comply with the BACT limit for at least CO of 0.04 lb/MMBtu through initial testing.

Please explain the meaning of "...thus, exempting the source from BACT for CO." and provide the citation of the legal authority for the exemption.

Response #9: These sources are being retrofit with NGULNB as a part of the expansion and, because they will experience decreases in CO emissions, are not required to undergo BACT for that pollutant. Please see Comment/Response #4 for this authority.

The purpose of this specific condition was to verify that actual CO emissions for these sources, post-retrofit, have not increased. These factors were back calculated from proposed annual CO limits, which correspond to no CO emission increases from these two sources.

Comment #10: Page 88, Table 14 – Process Heater BACT Limits: Please specify “time averaging” period for BACT limits listed in this Table (1-hour, 3-hour, or 24-hour). If there is more than one limit for those pollutants, ADEQ should list all of them for each time period.

Response #10: These limits are based upon a 3-hour average. Table 14 has been amended as requested. Testing requirements have also been amended to state that compliance with the BACT limits are based upon a 3-hour average.

Comment #11: Page 88, Specific Condition #64, BACT Requirements for Process Heaters: Lion proposed NOx BACT limit of 0.035 lb/MMBtu for SN-805N and of 0.045 lb/MMBTU for (SN-804) by using Good Combustion Practice and New NGULNB.

The Consent Decree requires that “Lion Oil reduce NOx emissions from the heaters and boilers listed in Appendix C by installing Next Generation Ultra Low-NOx Burners (Next Generation ULNB) or Alternative NOx Control Technology, and demonstrating continuous compliance with lower emission limits through the use of source testing, CEMs...” (Page 20)

The proposed permit indicates that NOx BACT will be the current ULNB level of 0.045 lb/MMBtu, for SN-804. This does not meet CD required Next Generation ULNB; further, the BACT emission for refinery heaters in current by issued permits can be as low as 0.0125 lbs NOx/MMBtu.

Lion installs a Next Generation ULNB (SN-805N) and proposes a NOx BACT limits of 0.035 lb/MMBTU. Information from John Zinc Company indicates that Next Generation ULNB is able to reduce more than 90% NOx emissions and allowed to emit NOx at 0.01 lb/MMBtu for units of 100 million Btu/hr or more. (See attached website) The heat capacity of SN-805N falls into this range (142 MBtu/hr) and should have no problem achieving the same level of emission reduction.

For your information on setting BACT limits, we have attached the Texas' proposal on NOx requirements indicating that the next generation ULNB can achieve levels of 0.010 lb/MMBtu.

EPA encourages the ADEQ to determine the feasibility of these burners for this expansion and reduce the BACT emissions rates for the next generation ULNB. ADEQ should provide EPA with the "top down" analysis or equivalent BACT analyses and its rationale for determining an emission limit for these sources.

Response #11: While emissions for refinery heaters are capable of achieving NO_x control at a level of 0.0125 lb/MMBTU, the above example is referring to heaters with add-on control technologies such as SCR. The facility has demonstrated through a cost-analysis that add-on control technologies are economically infeasible.

The facility has discussed the referenced John Zink Company (JZ) document with their equipment provider, Tulsa Heater Inc. (THI), and JZ. In those discussions, THI and JZ have acknowledged that NGULNBs are capable of achieving NO_x emissions levels on the order of 0.01 lb/MMBtu. However, 0.01 lb/MMBtu is only achievable under test standard conditions. The design criteria for Lion's heaters (i.e., air preheat, required heat output, temperatures, etc.) as well as actual field conditions (e.g., variable refinery fuel gas) will preclude the burners from meeting these absolute minimum NO_x emission levels. The heaters Lion has proposed for installation (JZ Coolburn technology) are, in fact, the next generation upgrade to the burners mentioned in the JZ document (LM300 burners). Lion will be installing the latest technology available for low-NO_x combustion. THI and JZ have reviewed the heater design criteria and are unwilling to guarantee NO_x emission rates any lower than the 0.035 lb/MMBtu proposed by Lion due to the service and performance requirements for the Expansion Project.

Comment #12: *Page 1-2 of the Permit Application, 5th paragraph: It states, "Table 1-2 lists the actual-to-potential emissions increases (or actual-to-projected actual increases for the FCCU) from the Refinery Expansion Project (considered by itself, without any decreases.)"*

Please define "actual-to-projected actual" increases for the FCCU. This unit is under modification. Is it possible to measure emissions before the project is done? PSD regulation requires the permittee uses potential to emit (PTE) for new project or modification of existent emission source.

Response #12: Actual-to-projected-actual applicability test for projects that only involve existing emissions units is defined in 40 CFR § 52.21(a)(2)(iv)(c). A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions for each existing emission unit, equals or exceeds the significant amount for that pollutant. As specified by (41)(ii)(d) of that section, the facility may elect to use the emissions unit's potential to emit, in tons per year, but are not required to do so.

Comment #13: *Chapter 2. ADEQ Operating Permit Application Form: EMISSION RATE TABLE is incomplete. Several modified sources were missing (i.e., No. 9 Hydrotreater*

Furnace Reboiler, No. 9 Stabilizer Re boiler, No.12 Unit Distillate Hydrotreater, Sulfur Recovery Plant Incinerator, and Tier 2 heater)

Response #13: These sources are not being modified with in this revision; therefore emission rate tables were not included in the application. These sources are experiencing an actual increase because of modified units but their potential to emit is remaining unchanged.

Comment #14: Neither the permit application nor the draft permit addresses start-up, shutdown, and malfunction (SSM) activities. SSM should be included in the Potential to Emit (PTE). SSM emissions must be subject to both the short-term and annual permitted emission limits and supported by adequate monitoring and record keeping provisions. BACT limits may not be waived during periods of SSM. BACT limits may be specified for varying modes of operation. However, ADEQ can make a determination that compliance with BACT emission limitations is infeasible during SSM activities and therefore may establish secondary BACT limits, provided it is made part of the Prevention of Significant Deterioration (PSD) permit.

Secondary BACT limits are typically represented by limits on the duration of such events and allowable emission rates during the events (hourly and/or per event). Secondary limits must be justified, as BACT and the permitting authority must ensure that all PSD requirements are met, including compliance with National Ambient Air Quality Standards (NAAQS) and PSD increment provisions.

Response #14: Lion Oil is expected to meet their emission limits at all times including periods of start-up, shut down, and malfunctions. In Arkansas, SSM emissions are covered in section 19.601 of Regulation 19. It states:

Any source exceeding an emission limit established by the Plan or applicable permit shall be deemed in violation of said Plan or permit and shall be subject to enforcement action.

Lion Oil did not include SSM emissions in either the baseline actual or the post-project emissions.

New or modified heaters are the only affected equipment with potential for SSM emissions (i.e., SO₂ emissions from noncompliant refinery fuel gas). However, the Expansion Project will have no impact on the fuel gas sweetening system or the H₂S content of the refinery fuel gas. Inclusion of SO₂ emissions from noncompliant refinery fuel gas in the baseline actual emissions would have served to improperly increase the baseline actual and thereby minimize the potential emissions increases associated with the project. Therefore, they were not included in the baseline actual for SO₂.

The Expansion Project will not affect flaring, the most common type of SSM emissions at the refinery. The types of equipment associated with the expansion are not expected to increase the likelihood of a flaring/SSM event. Additionally, the

flare gas recovery system at the refinery was designed to accommodate future refinery expansions, including the proposed expansion. If actual SSM/flaring emissions had been included in the baseline actual, then the same quantity of emissions would have been included in the post-project emissions resulting in a net zero emissions increase.

Comment #15: Emission Unit Information – Specific Conditions 66 and 68

Specific Conditions 66 and 68 each indicate that additional testing after initial compliance testing should be performed both every three years and every five years. Please delete the sentence requiring testing every three years after the initial compliance to clarify that periodic testing is required every five years.

Response #15: BACT limits shall be confirmed every five years through testing. The conflicting statement of three years has been removed from these BACT testing conditions.

Comment #16: Emission Unit Information – Specific Condition 74

In order to maintain language consistent with that of NSPS J, please revise Specific Condition 74(e)(ii) to read as follows:

The permittee has applied for approval from the US EPA for an alternative monitoring plan to demonstrate compliance with the opacity limit pursuant to Subpart J.

Response #16: The condition as been revised as requested.

Comment #17: Emission Unit Information, SN-809 #7 FCCU Catalyst Regenerator (Specific Condition 78).

- a. *The facility requests that Specific Condition 78 (FCCU PM testing) be revised to require compliance demonstration via EPA Test Method 5B, as stipulated in NSPS Subpart J and Refinery Consent Decrees rather than Methods 5 and 202. Requiring the measurement of condensable PM using Method 202 changes the underlying basis of the established BACT limit.*

Filterable and condensable particulate are fundamentally different. While filterable emissions are well understood, condensable emissions are more complex and more difficult to measure accurately. For filterable PM, which is captured by traditional PM control devices (e.g., ESPs and wet venture scrubbers), Lion expects that most controlled FCCU regenerators are capable of achieving essentially the same emission standard, i.e., the typical Refinery Consent Decree limit of 0.5 lb PM/1000 lb coke burn. Once condensable emissions, which may contain sulfuric and nitric acid, high molecular weight organics (i.e. molecules with 25 or more carbon atoms), and other compounds not necessarily controlled by traditional particulate

control devices are included, the achievable emission rate is much more variable.

Historically, most air quality permits only regulated filterable PM, as measured by Method 5 and/or 201. Numerous air permits for refinery FCCUs specify only the NSPS required test method or do not specify the underlying test methods at all (and are suspected of not including condensable emissions in most cases of omission). NSPS Subpart J requires the use of EPA Method 5B for FCCUs with wet gas scrubbers.

While the 0.5 lb/1000 lb coke burn-off particulate BACT limit is not specifically tied to the NSPS limit, it was arrived at based on Consent Decree limits that were established using the NSPS test procedures (i.e. Method 5B). The EPA states in the preamble to the proposed NSPS J and Ja rules that: "Condensable sulfates and other condensable compounds measured by Method 5 and 202 vary widely, but the average is about 0.5 kg/Mg of coke burn off."

Given the significant uncertainty and variability in Method 202, it is likely that Method 5 and Method 202 results (combined) would exceed the 0.5 lb/1000 lb limit. Lion Oil is not aware of any other refinery subject to a -.5 lb/1000 lb BACT limit using Method 5 plus Method 202 testing as the compliance demonstration mechanism. To require Method 5 plus Method 202 as the compliance demonstration mechanism would be to set a new standard that has not been demonstrated achievable.

- b. The initial stack testing cannot take place at the maximum coke burn rate until after the expansion project is complete because the FCCU will not be able to operate within 10 percent of the 15,000 lb/hr coke burn rate. Please revise language to require the initial test within 180 days of the start of normal operations after completion of the expansion project.*
- c. The maximum coke burn rate will be 15,000 lb/hr after project completion, not 15,000 lb/min.*
- d. Lion Oil feels that testing every three years after the initial compliance demonstration is excessive. The FCCU is equipped with continuous parameter monitors for the purpose of demonstrating compliance with particulate matter emission limits. Lion Oil believes that one performance test every five years after the initial compliance demonstration is adequate for demonstrating continuous compliance when considered in combination with Lion's continuous parameter monitoring.*

Response #17a: The Department acknowledges that EPA Reference Method 5B is the proper test method for the NSPS particulate standard. However, because this is a BACT limit

for PM₁₀, both condensable (including acid particulate) and filterable particulate less than ten microns must be taken into account, for which Method 5B alone is inadequate.

Other facilities – ConocoPhillips Co in Oklahoma, ConocoPhillips in Washington, and Premcor in Delaware - have been required to test condensable particulate from their FCC units using Method 202. The Washington facility, in a 2003 permit revision, has been required to meet a PM₁₀ (condensable and filterable) standard of 0.5 lb per thousand pounds of coke burn-off on a three-hour average. It is unclear and not readily apparent from the RACT/BACT/LAER Clearinghouse, whether any BACT limit for particulate from FCCUs has applied to both condensable and filterable particulate.

However, in light of the possible inaccuracy of the proposed particulate emission limit to quantify condensable and filterable particulate, the BACT limit of 0.5 lb/1000 lb coke shall apply to filterable particulate with compliance demonstrated through Method 5B. The facility shall then be required to evaluate through EPA Method 202 testing, a condensable particulate BACT limit and submit an application to the Department. These requirements are contained within Specific Conditions 29 and 30 of the final permit.

Response #17b: Particulate testing language has been revised to allow for the facility to complete the expansion project so that the source may be tested at or near the maximum coke burn rate. The source cannot achieve maximum coke burn until the project is completed. Testing shall be required no later than 180 days after project completion and normal operation.

Response #17c: The typographical error has been corrected. The coke burn rate is 15,000 lb/hr.

Response #17d: The particulate BACT compliance requirement has been changed to require periodic testing every five years.

Comment #18: Emission Unit Information – Specific Conditions 177 and 178

Lion proposes to limit the conductivity of the circulating water rather than limit TDS. Conductivity is directly related to the TDS content of a cooling tower. Lion proposes to monitor the conductivity of the circulating water weekly, and maintain records of the observed conductivity on a 52-week average, updated monthly.

Response #18: While conductivity monitoring can be used as a measurement of total dissolved solids, due to the limited data submitted, it is not clear what measurement would correspond to a TDS concentration of 3,000 mg/L. Therefore, the facility should concurrently with conductivity, determine TDS through a laboratory method, EPA Method 160.1 or ASTM 2540C for a period of six months. This condition has been modified such that conductivity shall be measured as a compliance mechanism for

TDS with the requirement of gathering more data to develop a more clear correlation. The condition has been rewritten as follows:

“The permittee shall monitor conductivity on a weekly basis and maintain these records on a continuous, rolling 52-week average. For an initial six month period after beginning operation of this source, the permittee shall, concurrently with conductivity measurements, perform TDS analysis using EPA Method 160.1 or ASTN 2540C. These records shall be kept on-site and shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]”

Comment #19: *Emission Unit Information – Specific Condition 196*

A new asphalt tank (T-new) was previously permitted and constructed at the Lion refinery. The initial application indicated that the T-New is subject to the requirements of NSPS UU. Please add T-new to the list of tanks that are subject to NSPS UU.

Response #19: Specific Condition 148 of the final permit has been amended to include T-New as an affected source of NSPS UU.

Comment #20: *Introduction – BACT Analysis*

The permit incorrectly states that SN-804 is not subject to BACT for NO_x and CO. The permit should state that SN-803 and SN-805 are not subject to BACT for NO_x and CO because they will be retrofit with ultra low NO_x burners before the refinery expansion is on line.

Response #20: The typographical error has been corrected in the final permit.

Comment #21: *Introduction – BACT Analysis*

In the discussion of the most effective controls for NO_x and SN-804, the sentence that states “the facility assumed a conservative 75% control of NO_x” is extraneous and should be deleted.

Response #21: The sentence has been removed as requested.

Comment #22: *Emission Unit Information – Table 12*

Please update the NO_x emission limit for SN-805 to reflect the post-project emission limit of 11.6 tpy.

Response #22: This typographical error has been corrected. The emission rate for SN-805 is 11.6 tpy NO_x.

Comment #23: *Emission Unit Information – Specific Condition 64*

Please correct the typo in Specific Condition 64. The word “shall” should be deleted.

Response #23: The typographical error has been corrected in Specific Condition #16 of the final permit.

*Comment #24: Emission Unit Information – Specific Condition 77
Please correct the typo in Specific Condition 77. The word “shall” should be deleted.*

Response #24: The typographical error has been corrected in Specific Condition #29 of the final permit.

*Comment #25: Emission Unit Information – Specific Condition 135
Please delete Specific Condition 135. It essentially duplicates Specific Condition 134.*

Response #25: Specific Condition 135 of the final permit has been removed as requested because it essentially duplicated language of the previous condition.

*Comment #26: Emission Unit Information – Table 34
Short-term fugitive emission limits are based on hourly rates, not daily rates. Please revise the heading in Table 34 to reference lb/hr limits instead of lb/day limits.*

Response #26: The typographical error has been corrected in Table 34 of the final permit. Other instances of incorrect lb/day notations were corrected as well.

Comment #27: During the comment period for this permit, the facility submitted an application for an administrative amendment. The facility wished to add an emergency generator as an A-1 Insignificant Activity.

Response #27: The source has been added as an A-1 Insignificant Activity to the permit. Also, the amine generators, an A-1 activity, have been removed. This source is no longer needed.

Comment #28: During the comment period, 40 CFR 63, Subpart DDDDD was vacated.

Response #28: All conditions required by this subpart, which are not required for compliance with any other emission rate or standard, have been removed. As a result of the vacatur, SN-805N will now be required to test CO emissions every five years to verify compliance with the BACT limit instead of through use of a CEM. The CEM was required by the MACT and could have also verified compliance with the BACT limit of 0.04 lb/MMBTU.

ADEQ OPERATING AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation No. 26:

Permit No. 868-AOP-R5

IS ISSUED TO:

**Lion Oil Co.
El Dorado, AR 71730
Union County
AFIN: 70-00016**

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO
INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION
UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE
FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

November 28, 2006

And

November 27, 2011

IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:



Mike Bates
Chief, Air Division

OCT 01 2007

Date Modified

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Table 1 - List of Acronyms

A.C.A.	Arkansas Code Annotated
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CSN	County Serial Number
HAP	Hazardous Air Pollutant
lb/hr	Pound per hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO _x	Nitrogen Oxide
PM	Particulate matter
PM ₁₀	Particulate matter smaller than ten microns
SNAP	Significant New Alternatives Program (SNAP)
SO ₂	Sulfur dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Ton per year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Section I: FACILITY INFORMATION

PERMITTEE: Lion Oil Co.

AFIN: 70-00016

PERMIT NUMBER: 868-AOP-R5

FACILITY ADDRESS: 1000 McHenry Avenue

El Dorado, AR 71730

MAILING ADDRESS 1000 McHenry Avenue

El Dorado, AR 71730

COUNTY: Union

CONTACT POSITION: Mr. Chuck Hammock, Environmental Manager

TELEPHONE NUMBER: (870) 864-1289

REVIEWING ENGINEER: Paula Parker

UTM Zone: 15

UTM North - South (Y): 3655.1

UTM East - West (X): 531.0

Section II: INTRODUCTION

Summary of Proposed Modification

Lion is planning projects to increase the capacity of the No. 4 Crude Distillation Unit (CDU) and the No. 7 Fluidized Catalytic Cracking Unit (FCCU). Lion plans to increase the capacity at the CDU from a crude throughput of approximately 70,000 barrels per day (BPD) to approximately 100,000 BPD. The expansion project will include:

- Redesign of the CDU featuring a new No. 4 Vacuum Furnace (SN-805N)

The new No. 4 Vacuum Furnace will be subject to the fuel gas H₂S content limitation for fuel gas combustion devices.

- Retrofit SN-803 and SN-805 with new, next generation ultra-low NO_x burners
- Increase the heat input capacity for SN-804

These sources will not experience an increase in NO_x or CO emissions. Therefore, a BACT analysis was not required for NO_x or CO from these two heaters. A PM₁₀ BACT analysis was still required. This retrofit is required by the Consent Decree. The annual heat input capacity for SN-804 is increasing to 280 MMBTU from 221 MMBTU.

- Increase the capacity at the FCCU (SN-809) from approximately 19,700 BPD to over 25,000 BPD.

No new emissions sources are included in the scope of the project for the FCCU expansion. However, emissions increases will result from the increased throughput.

- Install new, No. 9 Cooling Tower, SN-853-9
- Increase the gallons per minute flow rate through the No. 5 Cooling Tower

The #5 cooling tower was modified in 2005 to install drift eliminators for PM₁₀ control. As a result of the expansion project, the facility is increasing the water throughput at the #5 cooling tower. This source is increasing by 1.6 tpy particulate. The #9 Cooling Tower will be installed as a result of the refinery expansion. SN-853-9 was added to account for emissions from the source since these emissions were relied upon in the PSD netting analysis. Emissions from all seven cooling towers (3, 5, 6, 7, 8, 9, and 17) are bubbled together under SN-853. Cooling Tower #9 retains SN-853-9, for PSD purposes, although the emissions from this source are included in the SN-853 bubble.

- Install a new crude oil storage tank (T-998)

Due to the increase in crude throughput expected to result from the proposed project, the facility proposes to install an additional crude oil storage tank (T-998). The new crude tank

will be identical to T-120 and will be subject to 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC and UU.

- Replace G398TA Air Compressor (SN-841) with G3512TA (SN-841A)

Though unrelated to the expansion project, the facility is also proposing to replace the G398TA Air Compressor, rated at 700 hp, with a 815 hp unit, G3512TA (SN-841A). Once the new unit is operational, the facility will remove G398TA from service. The new unit shall be subject to 40 CFR Part 63, Subpart ZZZZ for Stationary Reciprocating Internal Combustion Engines.

Total Plantwide emissions of SO₂, VOC, CO, and NO_x are decreasing by 262.5, 622.1, 111.9, and 968.5 tpy respectively. PM₁₀ is increasing by 9.6 tpy.

Prevention of Significant Deterioration

Project Description

The net emissions increase for this project will exceed the PSD significant emission rates for nitrogen oxides (NO_x), particulate matter (PM₁₀), and carbon monoxide (CO). A summary of the net emissions increases that are above the PSD significant emission rates is contained in Table 2 through 7.

The first step is to calculate the "significant emissions increase" for the particular change. The procedure for calculating whether a significant emissions increase will occur depends upon the type of emissions units being modified. The Refinery Expansion Project involves both new and existing units. The only new emissions unit related to this project is the new No. 4 Vacuum Furnace (SN-805N). The existing emissions units affected by this project or experiencing an associated emissions increase are:

- Current No. 4 Pre-flash Column Reboiler (SN-803),
- Converted No. 4 Pre-flash Column Reboiler (SN-805, formerly the No. 4 Vacuum Furnace),
- No. 4 Atmospheric Furnace (SN-804),
- No. 7 FCCU Furnace (SN-808),
- No. 7 Catalyst Regenerator (SN-809),
- No. 9 Hydrotreater Furnace/Reboiler (SN-810),
- No. 9 Stabilizer Reboiler (SN-812),
- New Boilers (SN-821),
- No. 12 Unit Distillate Hydrotreater (SN-842),
- Sulfur Recovery Plant Incinerator (SN-844),
- Cooling Towers (SN-853),
- Facility Tanks PAL (SN-856),
- Naphtha Splitter Reboiler (SN-857),
- ULSD Hydrotreater Heater (SN-860),
- Hydrogen Plant Heaters (SN-861),
- and fugitive emissions (SN-854).

Table 2- Refinery Expansion Project Emissions Changes

Pollutant	Net Emission Increase (tpy)	PSD Significant Emission Rate (tpy)
PM ₁₀	36.5	15.0
SO ₂	96.0	40.0
VOC*	337.6	40.0
CO	130.9	100.0
NO _x	62.5	40.0

* the VOC term includes the contribution from air toxics and HAPs that are also VOCs.

Table 3- Refinery Expansion – PM₁₀ Emission Changes

Source Description	Emissions Change (tpy)	Notes
SN-803, Current No. 4 Pre-flash Column Reboiler	0.5	Based upon 2002/2003 actual emissions and maximum heat rating
SN-805, Converted No. 4 Pre-flash Column Reboiler	0.6	
SN-804, No. 4 Atmospheric Furnace	2.8	
SN-805N, New No. 4 Vacuum Furnace	4.7	1,249,085 MMBTU/yr
SN-808, No. 7 FCCU Furnace	0.8	Based upon 2002/2003 actual emissions and maximum heat rating
SN-809, No. 7 Catalyst Regenerator Stack	12.8	Increase at Unmodified Unit, based upon 2002/2003 actual emissions
SN-810, No. 9 Hydrotreater Furnace Reboiler	0.2	
SN-812, No. 9 Stabilizer Reboiler	0.1	

Source Description	Emissions Change (tpy)	Notes
SN-842, No. 12 Unit Distillate Hydrotreater	0.3	
SN-844, Sulfur Recovery Plant Incinerator	0.6	
SN-853, Cooling Towers	8.1	New No. 9 Cooling Tower, No. 5 Cooling Tower Increase
Naphtha Splitter Reboiler (SN-857), ULSD Hydrotreater Heater (SN-860), Hydrogen Plant Heaters (SN-861) Tier 2 Heaters	2.5	Based upon 2002/2003 actual emissions and maximum heat rating
Expansion Steam Demand Increase	2.5	419,908 MMBTU/yr increase from the boilers
Project Emission Change	36.5	Netting Required
Contemporaneous Projects		
SN-811, No. 9 Reformer Furnace	1.0	277,487 MMBTU/yr
Tier 2 Steam Demand Increase	0.5	78,556 MMBTU/yr
SN-831, No. 9 CCR	4.4	
SN-844, Sulfur Recovery Plant	39.6	Based on stack testing
SN-809, No. 7 FCCU Catalyst Regenerator	-10.0	Consent Decree
Tier 2 Heaters	12.2	2,064,240 MMBTU/yr
SN-859, No. 1 Cooling Tower Replacement	-30.2	
SN-821a,b,c, New Refinery Boilers	31.1	

Source Description	Emissions Change (tpy)	Notes
SN-863, Boiler Feedwater Pumps	0.1	
SN-816 thru 820, Shutdown Boilers	-7.3	Removed from Service
SN-832, Tank Heater	0.1	Consent Decree (CIV. No. 03-1028) Installed 2001 T-112
SN-856 and 862, New 150,000 bbl Asphalt Tank w/Heater	1.3	
SN-813a, New No. 10 Unit Heater	1.0	Avg. of 2002/2003 actual emissions
SN-839 and 840, JVG Compressors	-0.4	Converted to Electrical Power
SN-837 and SN-838, SVG Compressors	-0.8	
SN-848, No. 7 FCCU Catalyst Hopper Vents	-0.8	Routed to the wet gas scrubber of the #7 FCCU unit (SN-809)
SN-843, #12 Stripper Reboiler Heater Shutdown	-0.6	
SN-853a, Drift Eliminators In Cooling Tower #5	-26.3	
Double Counted Emissions		
Expansion Steam Demand Increase	-2.5	Emissions are already accounted for in Contemporaneous projects and as Associated Increases at Unchanged Units
Tier 2 Project Steam Increase	-0.5	
Tier 2 Heaters	-2.5	
Sulfur Recovery Plant	-0.6	
Net Emission Change	45.3	Significant

Table 4- Refinery Expansion – SO₂ Emission Changes

Source Description	Emissions Change (tpy)	Notes
SN-803, Current No. 4 Pre-flash Column Reboiler	2.3	Based upon 2002/2003 actual emissions and maximum heat rating
SN-805, Converted No. 4 Pre-flash Column Reboiler	2.6	
SN-804, No. 4 Atmospheric Furnace	12.8	
SN-805N, New No. 4 Vacuum Furnace	21.0	1,249,085 MMBTU/yr
SN-808, No. 7 FCCU Furnace	3.6	Based upon 2002/2003 actual emissions and maximum heat rating
SN-809, No. 7 Catalyst Regenerator Stack	25.5	Increase at Unmodified Unit, based upon 2002/2003 actual emissions
SN-810, No. 9 Hydrotreater Furnace Reboiler	0.8	
SN-812, No. 9 Stabilizer Reboiler	0.3	
SN-842, No. 12 Unit Distillate Hydrotreater	1.2	
SN-844, Sulfur Recovery Plant Incinerator	12.2	
Naphtha Splitter Reboiler (SN-857), ULSD Hydrotreater Heater (SN-860), Hydrogen Plant Heaters (SN-861) Tier 2 Heaters	7.3	Based upon 2002/2003 actual emissions and maximum heat rating
Expansion Steam Demand Increase	6.4	419,908 MMBTU/yr increase from the boilers
Total	96.0	Netting Required

Source Description	Emissions Change (tpy)	Notes
Contemporaneous Projects		
SN-811, No. 9 Reformer Furnace	4.7	277,487 MMBTU/yr
SN-844, Sulfur Recovery Plant	28.2	
Tier 2 Steam Demand Increase	1.2	78,566 MMBTU/yr
Tier 2 Heaters	34.9	2,064,240 MMBTU/yr
SN-809, No. 7 FCCU Catalyst Regenerator	-35.0	Consent Decree
SN-821a,b,c, New Refinery Boilers	81.3	
SN-863, Boiler Feedwater Pumps	0.1	
SN-816-820, Shutdown Old Boilers	-1.6	Removed from Service
SN-822 and 823, Flare Gas Recovery	-252.2	
SN-832, New Tank Heater	0.2	Installed 2001
SN-856 and 862, New 150,000 bbl Asphalt Tank w/Heater	5.3	T-112
SN-813a, New No. 10 Unit Heater	2.8	Avg. of 2002/2003 actuals
SN-843, #12 Stripper Reboiler Heater Shutdown	-0.2	
Double Counted Emissions		
Plant Expansion Steam Increase	-6.4	Emissions are already accounted for in Contemporaneous projects and as Associated
Tier 2 Project Steam Increase	-1.2	

Source Description	Emissions Change (tpy)	Notes
Tier 2 Heaters	-7.3	Increases at Unchanged Units
Sulfur Recovery Plant Incinerator	-12.2	
Net Emission Change	-61.4	

Table 5- Refinery Expansion – VOC Emission Changes

Source Description	Emissions Change (tpy)	Notes
SN-803, Current No. 4 Pre-flash Column Reboiler	0.4	Based upon 2002/2003 actual emissions and maximum heat rating
SN-805, Converted No. 4 Pre-flash Column Reboiler	0.4	
SN-804, No. 4 Atmospheric Furnace	2.0	
SN-805N, New No. 4 Vacuum Furnace	3.4	1,249,085 MMBTU/yr
SN-808, No. 7 FCCU Furnace	0.6	Based upon 2002/2003 actual emissions and maximum heat rating
SN-809, No. 7 Catalyst Regenerator Stack	8.0	Increase at Unmodified Unit, based upon 2002/2003 actual emissions
SN-810, No. 9 Hydrotreater Furnace Reboiler	0.1	
SN-812, No. 9 Stabilizer Reboiler	0.1	
SN-842, No. 12 Unit Distillate Hydrotreater	0.2	
SN-844, Sulfur Recovery Plant Incinerator	0.8	
SN-847, Heavy Oil Loading Rack	123.3	Increase at Unmodified Unit

Source Description	Emissions Change (tpy)	Notes
SN-853, Cooling Towers	20.6	New No. 9 Cooling Tower, Increased flowrate at No. 5 Cooling Tower
SN-854, Fugitive Emission Increase	14.7	Associated Increase at Unchanged Source
SN-856, Facility Tanks Emission Increase	156.9	
Naphtha Splitter Reboiler (SN- 857), ULSD Hydrotreater Heater (SN-860), Hydrogen Plant Heaters (SN-861) Tier 2 Heaters	3.2	Based upon 2002/2003 actual emissions and maximum heat rating
SN-821, Expansion Steam Increase	3.1	419,908 MMBTU/yr increase from the boilers
Total	337.8	Netting Required
Contemporaneous Projects		
SN-811, No. 9 Reformer Furnace	0.7	277,487 MMBTU/yr
Tier 2 Steam Demand Increase	0.6	78,566 MMBTU/yr
SN-854, Tier 2 Fugitive Equipment Leaks	-50.3	NSPS GGG Monitoring
SN-856, Tank 54	18.3	Throughput increase
SN-856, Tank 108	0.2	
SN-856, Tank 109	1.1	
SN-856, Tank 113	-11.2	Change and Retrofit
SN-856, Tank 119	9.4	Throughput Increase
SN-856, Tank 121	12.1	
SN-856, Tank 122	13.5	

Source Description	Emissions Change (tpy)	Notes
SN-856, Tank 247	2.4	Service Change and Retrofit
SN-856, Tank 372	-15.8	
Tier 2 Heaters	15.4	
SN-821a,b,c, New Refinery Boilers	39.1	
SN-863, Boiler Feedwater Pumps	0.2	
SN-816-820, Shutdown Old Boilers	-5.3	Removed from Service
SN-856, Gas Oil Tanks	12.0	
SN-851, Enclosed Process Water Treatment	-1769.4	
SN-856, Tank 82	18.3	
SN-856, Tank 201	0.6	
SN-856 and 862, New 150,000 bbl Asphalt Tank w/Heater	0.9	
SN-813a, New No. 10 Unit Heater	0.7	
SN-839 and 840, JVG Compressors	-0.7	Converted to Electrical Power
SN-837 and SN-838, SVG Compressors	-1.3	
SN-843, #12 Stripper Reboiler Heater Shutdown	-0.5	
Double Counted Emissions		
Plant Expansion Steam Increase	-3.1	Emissions are already accounted for in

Source Description	Emissions Change (tpy)	Notes
Tier 2 Project Steam Increase	-0.6	Contemporaneous projects and as Associated Increases at Unchanged Units
Tier 2 Heaters	-3.2	
Net Emission Change	-1378.1	Not Significant

Table 6 - Refinery Expansion – CO Emission Changes

Source Description	Emissions Change (tpy)	Notes
SN-804, No. 4 Atmospheric Furnace	15.1	Based upon 2002/2003 actual emissions and maximum heat rating
SN-805N, New No. 4 Vacuum Furnace	25.0	1,249,085 MMBTU/yr
SN-808, No. 7 FCCU Furnace	8.7	Based upon 2002/2003 actual emissions and maximum heat rating
SN-809, No. 7 Catalyst Regenerator Stack	44.6	Increase at Unmodified Unit, based upon 2002/2003 actual emissions
SN-810, No. 9 Hydrotreater Furnace Reboiler	2.0	
SN-812, No. 9 Stabilizer Reboiler	0.8	
SN-842, No. 12 Distillate Hydrotreater	2.9	
SN-844, Sulfur Recovery Plant Incinerator	4.1	
Naphtha Splitter Reboiler (SN-857), ULSD Hydrotreater Heater (SN-860), Hydrogen Plant Heaters (SN-861) Tier 2 Heaters	18.0	Based upon 2002/2003 actual emissions and maximum heat rating

Source Description	Emissions Change (tpy)	Notes
Expansion Steam Demand Increase	9.7	419,908 MMBTU/yr increase from the boilers
Total	130.9	Netting Required
Contemporaneous Projects		
SN-811, #9 Reformer Heater	11.4	277,487 MMBTU/yr
Tier 2 Steam Demand Increase	1.8	
Tier 2 Heaters	85.2	2,064,240 MMBTU/yr
SN-821a,b,c, New Refinery Boilers	123.2	
SN-863, Boiler Feedwater Pumps	0.5	Removed from Service
SN-816-820, Shutdown Boilers	-80.5	Removed from Service
SN-832, Tank Heater	0.4	
SN-856 and 862, New 150,000 bbl Asphalt Tank w/Heater	14.2	Installed 2001 T-112
SN-813a, New No. 10 Unit Heater	-4.4	
SN-839 and 840, JVG Compressors	-14.0	
SN-837 and SN-838, SVG Compressors	-14.1	Source to be removed
SN-834 and SN-835, KVG Compressors	-0.1	Replaces G398TA
SN-841, G398TA Air Compressor	-13.3	Source to be removed
SN-841A, G3512TA Air Compressor	23.7	Replaces G398TA

Source Description	Emissions Change (tpy)	Notes
SN-843, #12 Stripper Reboiler Heater Shutdown	-7.0	
Double Counted Emissions		
Plant Expansion Steam Increase	-9.7	Emissions are already accounted for in Contemporaneous projects and as Associated Increases at Unchanged Units
Tier 2 Project Steam Increase	-1.8	
Tier 2 Heaters	-18.0	
Net Emissions Change	228.4	Significant

Table 7 - Refinery Expansion – NO_x Emission Changes

Source Description	Emissions Change (tpy)	Notes
SN-804, No. 4 Atmospheric Furnace	17.0	Based upon 2002/2003 actual emissions and maximum heat rating
SN-805N, New No. 4 Vacuum Furnace	21.9	1,249,085 MMBTU/yr
SN-810, No. 9 Hydrotreater Furnace/Reboiler	2.5	Increase at Unmodified Unit, based upon 2002/2003 actual emissions
SN-812, No. 9 Stabilizer Reboiler	1.4	
SN-842, No. 12 Unit Distillate Hydrotreater	2.9	
SN-844, Sulfur Recovery Plant Incinerator	3.1	
Naphtha Splitter Reboiler (SN-857), ULSD Hydrotreater Heater (SN-860), Hydrogen Plant Heaters (SN-861) Tier 2 Heaters	9.1	Based upon 2002/2003 actual emissions and maximum heat rating

Source Description	Emissions Change (tpy)	Notes
Expansion Steam Demand Increase	4.6	419,908 MMBTU/yr increase from the boilers
Total	62.5	Netting Required
Contemporaneous Projects		
SN-811, #9 Reformer Furnace	13.9	277,487 MMBTU/yr
Tier 2 Steam Demand Increase	0.9	78,566 MMBTU/yr
Tier 2 Heaters	42.2	2,064,240 MMBTU/yr
SN-821a, b, c, New Refinery Boilers	58.0	
SN-863, Boiler Feedwater Pumps	5.7	
SN-816-820, Shutdown Old Boilers	-58.6 ¹	Removed from Service
SN-832, New Tank Heater	0.5	Consent Decree (CIV. No. 03-1028)
SN-832, New 150,000 bbl Asphalt Tank w/Heaters	11.0	Installed 2001 T-112
SN-839 and 840, JVG Compressors	-9.2 ²	Converted to Electrical Power
SN-837 and SN-838, SVG Compressors	-9.3	
SN-834 and SN-835, KVG Compressors	-6.7	
SN-841, G398TA Air Compressor	-13.3	Source to be removed
SN-841A, G3512TA Air Compressor	15.8	Replaces G398TA
SN-843, #12 Stripper Reboiler Heater Shutdown	-5.4	

Source Description	Emissions Change (tpy)	Notes
Double Counted Emissions		
Plant Expansion Steam Increase	-4.6	Emissions are already accounted for in Contemporaneous projects and as Associated Increases at Unchanged Units
Tier 2 Project Steam Increase	-0.9	
Tier 2 Heaters	-9.1	
Total	93.4	Significant
¹ Per an agreement between Lion Oil, ADEQ, and the US EPA, the creditable NO _x emissions decrease from the shutdown of the old boilers is based on an emission rate of 0.06 lb/MMBtu rather than the actual emission rate of approximately 0.24 lb/MMBtu. Creditable decrease for Tier 2 Project is 10.0 tpy per Consent Decree (CIV. No. 03-1028).		
² The creditable emission reduction from the conversion of the JVG Compressors is limited to the most recently permitted emission level of 4.6 tpy for each unit. This level is lower than the average past emissions from these units.		

Modeling

PSD modeling is to be performed in two stages: the significance analysis and the full impact analysis. The significance analysis considers the net emissions change associated with PSD affected emission units to determine if the increased emissions will have a significant impact on the surrounding area. If the results of the significance analysis are below the corresponding Modeling Significance Levels the full impact analysis is not required.

The significance analysis considers the net emissions change associated with new, modified, and affected emissions units to determine whether or not the increased emissions have a significant impact upon off-property receptors. Significant impacts are defined by ambient concentration thresholds that are commonly referred to as Modeling Significant Levels.

In the significance analysis, PM₁₀, NO_x, and CO were modeled. The significance analysis shows the impacts from the sources that will experience an increase or decrease in emissions due to the project. PM₁₀ and NO_x are above the Modeling and Monitoring Significance level. CO is below both levels.

Averaging Period	Highest Modeled PM ₁₀ Concentration (μg/m ³)	Modeling Significance Level (μg/m ³)	Monitoring De Minimis Concentration (μg/m ³)
24-Hour	14.1	5.0	10.0

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Averaging Period	Highest Modeled PM ₁₀ Concentration ($\mu\text{g}/\text{m}^3$)	Modeling Significance Level ($\mu\text{g}/\text{m}^3$)	Monitoring De Minimis Concentration ($\mu\text{g}/\text{m}^3$)
Annual	1.36	1.0	-

Averaging Period	Highest Modeled NO _x Concentration ($\mu\text{g}/\text{m}^3$)	Modeling Significance Level ($\mu\text{g}/\text{m}^3$)	Monitoring De Minimis Concentration ($\mu\text{g}/\text{m}^3$)
Annual	2.32	1.0	14.0

Averaging Period	Highest Modeled CO Concentration ($\mu\text{g}/\text{m}^3$)	Modeling Significance Level ($\mu\text{g}/\text{m}^3$)	Monitoring De Minimis Concentration ($\mu\text{g}/\text{m}^3$)
8-Hour	169	500	575
1-Hour	76.5	2000	-

Class II Impact Analysis

Preliminary modeling of the proposed project indicated a significant impact (maximum impact at or above the PSD significance levels) for PM₁₀ and NO_x. Therefore PSD review requires the facility to perform a full air quality analysis to demonstrate compliance with the PSD Class II Increments. According to the modeled emission rates, neither pollutant exceeded the allowable increment. As required under 19.903 of Regulation 19, neither pollutant exceeded 50% of the available annual increment or 80% of the short term increment.

Averaging Period	Highest Modeled PM ₁₀ Concentration ($\mu\text{g}/\text{m}^3$)	Allowable Increment ($\mu\text{g}/\text{m}^3$)
Annual	4.19	17
24-Hour	23.2	30

Averaging Period	Highest Modeled NO _x Concentration ($\mu\text{g}/\text{m}^3$)	Allowable Increment ($\mu\text{g}/\text{m}^3$)

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Averaging Period	Highest Modeled NO _x Concentration (μg/m ³)	Allowable Increment (μg/m ³)
Annual	10.1	20

PSD Ambient Monitoring Requirements

If an ambient impact exceeds an applicable Monitoring De Minimis Concentration, the applicant must demonstrate that adequate monitoring data are presently available or submit a plan outlining an alternative monitoring strategy.

Because both the PM₁₀ significance analysis maximum 24-hour impact is greater than the applicable Monitoring De Minimis Concentration. Thus, preconstruction monitoring requirements must be addressed for PM₁₀.

In specific, defined cases, EPA guidance allows the use of existing "representative air quality data" in place of installing expensive monitoring equipment. The refinery is a Case II situation as defined in this guidance. It is located in an area of multi-source emissions and flat terrain. The ADEQ operates a PM₁₀ ambient monitor (now monitoring PM_{2.5}) approximately 1.7 km northeast of the refinery. This is well within the 10 km required by Case II, thus Case II is appropriate, and representative ambient monitoring data can be used in lieu of on-site data. Ambient monitoring data can be obtained from the EPA's AirData system. Lion proposes to use ambient PM₁₀ data from the El Dorado, Arkansas, monitor to satisfy the PSD preconstruction monitoring requirements and to represent the background concentration of PM₁₀. The annual-average PM₁₀ concentration selected from this monitor is 11.8 μg/m³ and the 2nd-high 24-hour PM₁₀ concentration is 25.0 μg/m³.

Since the NO₂ significance analysis maximum annual impact is less than the applicable Monitoring De Minimis Concentration, preconstruction monitoring is not required for NO₂. There is no ambient monitor for NO₂ in El Dorado. Lion proposes to use ambient NO₂ data from the North Little Rock, Arkansas, monitor to represent background concentrations of NO₂. The annual-average NO₂ concentration selected from this monitor is 21.6 μg/m³.

Full Impact Analysis

By modeling the total potential emissions of PM₁₀ and NO_x with competing source emissions, the facility determined the maximum predicted impacts. According to the modeling, there were no exceedences of the NAAQS for PM₁₀ or NO_x.

Averaging Period	Highest Modeled PM ₁₀ Concentration (μg/m ³)	Background Concentration (μg/m ³)	Total PM ₁₀ Concentration (μg/m ³)	PM ₁₀ NAAQS (μg/m ³)
Annual	7.94	11.8	19.74	50
24-Hour	60.6	25.0	85.6	150

Averaging Period	Highest Modeled NO _x Concentration (μg/m ³)	Background Concentration (μg/m ³)	Total Concentration (μg/m ³)	NAAQS (μg/m ³)
Annual	17.6	21.6	39.2	100

Class I Area Analysis

The nearest Class I area is the Caney Creek Wilderness, which is approximately 180 km from the refinery. The permittee analyzed plume impacts to visibility using VISCREEN. The VISCREEN model is used to determine whether a plume from a facility may be visible from a given point. VISCREEN performs visibility calculations for two assumed plume-viewing backgrounds, sky and terrain object.

The output of VISCREEN in a Level 1 analysis has two components. ΔE is used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A ΔE of less than 2.0 signifies that the plume is not perceptible. Contrast is the measure of contrast at a given wavelength of two colored objects such as plume/sky or plume/terrain. The analysis is generally considered satisfactory if ΔE and Contrast are less than critical values of 2.0 and 0.05, respectively. In this case, facility impacts both inside and just outside the nearest Class I area were acceptable, ΔE measuring 0.004 and contrast 0.000. Therefore, there are no significant plume impacts from this project.

In measuring impacts of PM₁₀ and NO_x to the nearest Class I area, the facility instead used AERMOD out to 50 km. No significant impacts were found. The highest annual PM₁₀ and NO_x concentrations over a five year period was 0.003 and 0.0054 μg/m³. The highest 24-hour PM₁₀ impact was 0.12 μg/m³.

Pollutant	Averaging Period	Maximum Impact(μg/m ³)	Significant Impact Level
PM ₁₀	24-hr	0.12	0.3
	Annual	0.003	0.2
NO _x	Annual	0.0054	0.1

Additional Impacts Analysis

An additional impact analysis is completed based on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the project's area of impact. The additional impact analysis consists of three parts: (1) growth, (2) soils and vegetation impacts, and (3) visibility impairment. Each of these analyses is presented in this section.

The purpose of the growth analysis is to predict the amount of new growth likely to occur to support the proposed project under review and to estimate the emissions that will result from the associated growth.

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SN-803, 804, SN-805, and SN-805N

The combustion sources that will be modified or installed and will also experience a net emissions increase as part of the Crude Unit Expansion Project are subject to BACT. The four new or modified process heaters (with heat input capacities of 40, 280, 75, and 142.2 MMBtu/hr) will burn refinery fuel gas (RFG). Other existing refinery process heaters are either not undergoing physical modifications or are not experiencing a net emissions increase associated with the Crude Unit Expansion Project; therefore, no other BACT analyses are required. Other refinery process heaters may have an increase in actual fired duty associated with this project. Heaters merely experiencing a change in actual fired heat duty are not subject to a BACT analysis because firing these units at a higher rate is neither a physical change nor a change in the method of operation.

SN-803 and SN-805 are not subject to BACT for NO_x and CO because these sources are being replaced with ultra low NO_x burners before the refinery expansion will come on line, and thus, will experience decreases in NO_x and CO.

BACT for Particulate Matter (PM/PM₁₀)

1. Identify all Control Technologies

Emission control equipment that may be selected to control particulate matter emissions from these combustion sources includes ESPs, baghouses, cyclones and high efficiency wet scrubbers. ESPs and baghouses/fabric filters can achieve particulate matter removal efficiencies as high as 99%. Scrubber particulate collection efficiencies range as low as 70% to as high as 99%, depending upon the application. Control efficiencies for cyclones vary greatly, depending upon the type. The high-efficiency cyclones can control PM₁₀ from 65 to 90%.

Searches of the RBLC were conducted to identify control technologies for the control of PM/PM₁₀ emissions from refinery-gas fired process heaters. All of the entries, with just a single exception of a spray chamber, indicate the use of combustion control and gaseous fuel to control PM/PM₁₀ emissions from refinery-gas fired heaters.

2. Eliminate Technically Infeasible Options

While ESPs and baghouses are the most efficient control devices for particulate removal, the expected particulate concentration from the combustion gas is too low for these options to be feasible. Baghouses are typically used for air streams with inlet pollutant concentrations of 0.5 to 10 gr/scf, but in extreme cases, may accommodate streams of 0.1 gr/scf to 100 gr/scf. Pollutant streams in excess of 550 °F require special materials for the bags, which can increase the cost. Typical inlet pollutant concentrations for ESPs range from 1 to 50 gr/scf, though can be as below as 0.5 gr/scf. ESPs can operate up to temperatures of 1300°F. Cyclones typically handle particulate loading from 1 to 100 gr/scf and inlet temperatures of up to 1000°F. Inlet streams for wet gas scrubbers (venturi) are between 0.1 and 50 gr/scf and temperatures ranging from 40 to 750°F.

Expected loading for these natural gas fired sources are much lower than typical inlet streams for these control devices - 0.004 gr/scf. Exhaust streams from these units have temperatures ranging from 370 to 853 °F. While these temperatures fall within the range of the above mentioned control devices, particulate loading from these gas combustion sources would be far too low for effective control. Therefore, the facility has eliminated add on controls as BACT.

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First, an assessment is made regarding the amount of residential growth the proposed project will bring to the area. This depends on the size of the available work force, the number of new employees, and the availability of housing in the area. Associated commercial and industrial growth consists of new sources providing goods and services to the new employees and to the new source itself. Once these anticipated growth effects have been considered, an estimate of the air pollutant emissions that would likely result from the associated growth is made. The assessment of additional growth issues and the estimates of emissions increases are conducted based on several types of EPA guidance.

Analysis of the impact of air emissions on soils and vegetation is based on an inventory of the soils and vegetation types found in the impact area. This inventory includes all vegetation of any commercial or recreational significance. For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS do not result in harmful effects.

The visibility impairment analysis considers the impacts that occur within the impact area of the modified source. The visibility analysis considers issues similar to the Class I area visibility analysis requirements.

Impacts Upon Soils and Vegetation

The secondary NAAQS are designed to protect soils and vegetation. As shown below, the proposed project will not cause or contribute to a violation of the NAAQS. As such, no adverse impact on soils or vegetation is predicted.

Impacts on Visibility

The project's maximum visibility impairment is predicted at PSD Class I areas to be below the Federal Land Manager's (FLM) screening criteria of 5% change (modeling net emission changes). The results of the short-range analyses combined with the distance from the nearest Class I area make it reasonable to conclude that the proposed project will not exceed a Class I area Increment standard and will not adversely affect Class I area air quality related values.

Impacts on Growth

While the proposed project is expected to increase production capacity at the refinery, no new full-time positions are expected to be created as a result of the project. Thus, no residential growth is expected to result from the proposed project. In addition, the shipping of raw materials and products to and from the facility is not expected to significantly increase the level of rail or ground traffic in the area. Since no significant associated growth is expected, negligible growth-related air pollution impacts are expected as a result of any industrial, commercial, or residential growth associated with the proposed project.

BACT Analysis

The BACT requirements of the PSD program only apply to the pollutants that are subject to PSD review and the emission units that are newly installed or physically modified. The potential increase in emissions of CO, PM₁₀, and NO_x resulting from the proposed and modified emissions sources at the Lion Refinery will exceed the respective PSD significant emission rates. Therefore, the CO, PM₁₀, and NO_x emissions are subject to PSD review, and any new and physically modified emission units experiencing a net emissions increase are subject to a BACT analysis.

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3. Rank Remaining Control Technologies

The only remaining, feasible control is good combustion practice and use of gaseous fuel. However, while a wet gas scrubber was selected as BACT for a RBLC entry, such a control device in this case would be economically infeasible.

4. Evaluate Most Effective Controls

The only remaining control option is good combustion practice and the use of gaseous fuel.

5. Select BACT

The facility proposes to use good combustion practice to satisfy the PM₁₀ BACT requirements. The selected BACT requirements presented for the process heaters are consistent with recent BACT determinations for process heaters located at petroleum refineries (SIC Code 2911) listed in the U.S. EPA's RBLC.

BACT for CO

1. Identify all Control Technologies

Add-on control technologies for CO in refinery heaters consist of thermal and catalytic incineration. Thermal incineration oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. A catalytic incinerator, similar to a thermal incinerator; operates by heating the waste stream is heated by a flame and then passing it through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Both methods involve additional sources of combustion pollutants.

Good combustion practice, while not an add-on control, still can be an effective means of limiting CO emissions from these heaters. Good combustion practice includes operational and design elements to ensure sufficient combustion air supply, temperature, residence time, and mixing in order to minimize emissions and ensure complete combustion.

Searches of the RBLC were conducted to identify control technologies for the control of CO emissions from refinery-gas fired process heaters. Entries indicate the use of combustion control, ultra low-NO_x burners, and gaseous fuel to control CO emissions from refinery-gas fired heaters.

2. Eliminate Technically Infeasible Options

All the aforementioned control technologies are feasible in controlling CO emissions from refinery-gas fired heaters.

3. Rank Remaining Control Technologies

Catalytic incineration and thermal incineration have respective efficiencies of 94 and 88%. ULNB can provide CO control along with NO_x control, and is already proposed as BACT for NO_x. Combustion control, while a pollution prevention technique, may be able to reduce NO_x as much as 70%.

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4. Evaluate Most Effective Controls

While catalytic incineration may provide up to 94% control for NO_x , would be upwards of \$10,000/ton of controlled emissions and is not economically feasible. Thermal incineration would be even more expensive per ton of pollutant controlled, with costs up to \$25,552/ton. The only remaining option would be combustion control.

5. Select BACT

The facility proposes to use good combustion practice to satisfy the CO BACT requirements. The selected BACT requirement is consistent with recent BACT determinations for process heaters located at petroleum refineries (SIC Code 2911) listed in the U.S. EPA's RBLC. The selected CO BACT limit for the process heaters (0.04 lb/MMBtu) is based on manufacturer's specifications for similar burners from at least two different vendors. The facility noted CO limits lower than 0.04 lb/MMBtu in the RBLC. However, upon further research into those entries, the permittee found that several limits were erroneous. Specifically, facilities had difficulty complying with the low limits, compliance demonstrations were much less stringent (i.e., one-time stack tests versus either annual stack testing or a CEMS), and in some cases, no compliance demonstration was required at all. Therefore, the facility believes the RBLC (as supplemented by the aforementioned research) supports the vendor-specified CO emissions performance of 0.04 lb/MMBtu for SN-804 and SN-805.

BACT for NO_x

1. Identify all Control Technologies

The add-on technologies for combustion control include: Selective non-catalytic reduction (SNCR) (25-70% reduction), selective catalytic reduction (SCR) (up to 90% reduction), and flue gas recirculation. SNCR systems work by injecting ammonia or urea into the combustion chamber of the boiler, thereby converting NO_x to elemental nitrogen, nitrogen dioxide, and water vapor. Catalysts in an SCR system can lose their activity over time due to poisoning, thermal sintering, binding/plugging/fouling, or erosion and aging. Similar to an SNCR system, an SCR system requires an aqueous or anhydrous ammonia or urea storage, feed and control system to operate properly. Recirculation of cooled flue gas reduces temperature by diluting the oxygen content of combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the NO_x concentration that is generated. Water/steam Injection is another method of reducing NO_x formation. The injection of water or steam into the main flame reduces the flame temperature and the generation of thermal NO_x . If the temperature is reduced, thermal NO_x will not be formed in as great a concentration.

Low NO_x burners are typically staged air with internal flue gas recirculation for gaseous fuels without external equipment. This design is predominately used for gas fuel applications. Ultra low NO_x burners use IFGR with an increased number of finely drilled burner tips to further reduce flame temperature and NO_x concentration.

Searches of the RBLC were conducted to identify control technologies for the control of NO_x emissions from refinery-gas fired heaters. Entries included low NO_x burners, ultra low NO_x burners, SCR, and Flue gas recirculation, or combination thereof. As a result of the Consent Decree, SN-804 currently employs ultra Low NO_x burner design, though the current generation of burners is slightly more

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efficient.

2. Eliminate Technically Infeasible Options

SNCR is technically infeasible due to the concentration of NO_x in the flue gas being less than 50 ppmv. The typical range of inlet pollutant concentration controlled by SNCR is between 200 and 400 ppmv. SCR, flue gas recirculation, low NO_x burners, and ultra low NO_x burners are the remaining technically feasible control options. The facility contends that water/steam injection is infeasible due to the increase in fuel requirements (If the flame temperature is sufficiently quenched, the generation of CO can increase and the process efficiency will decrease, resulting in an increase in fuel usage) and lack of available data on its effectiveness compared to NGULNB.

3. Rank Remaining Control Technologies

SCR, flue gas recirculation, low NO_x burners, and ultra low NO_x burners are the remaining technically feasible control options. SCR, ultra low NO_x and low NO_x (in descending order) have the highest potential emission reductions, up to 90%, from these control options. Flue gas recirculation could have up to 70% reduction in NO_x. Flue gas recirculation will not be considered further in this analysis.

4. Evaluate Most Effective Controls

SCR, while technically feasible, is not economically feasible to control NO_x, with costs ranging upwards of \$13,734 per ton controlled. The cost to outfit SN-804 with the current ULNB design would be upwards of \$10,000/ton of additional controlled emissions and is not therefore economically feasible.

5. Select BACT

The facility proposes as BACT, the current ULN design of SN-804 and the next generation ULN for SN-805N. The selected NO_x BACT limits for SN-804 and SN-805N, 0.045 and 0.035 lb/MMBtu, respectively, are based on the Consent Decree limit for SN-804 and manufacturer guarantees for the latest next generation ultra-low NO_x burners (NGULNB) used in conjunction with the process heater firing systems for SN-805N.

SN-809

Particulate Matter (PM/PM₁₀)

1. Identify all Control Technologies

Emission control equipment that may be selected to control particulate matter emissions from FCCU units include wet ESPs, baghouses, cyclones and wet scrubbers.

Searches of the RBLIC were conducted to identify control technologies for PM/PM₁₀ emissions from these units. A majority of the entries that require controls indicate the use of wet gas scrubbers for particulate. Two entries required the use of a cyclone and wet scrubber for particulate control, with a 90% overall efficiency. Another entry required the use of an ESP.

2. Eliminate Technically Infeasible Options

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A baghouse as control for particulate is not feasible because the regenerator flue gas leaves the heat recovery unit between 600 and 750°F. This exceeds the maximum baghouse operating temperature and may cause fire or explosion. The facility also indicates that cyclone control is not feasible due to their deficiency in removing particles 30 microns and smaller. The remaining control options are wet gas scrubbers and wet ESPs.

3. Rank Remaining Control Technologies

A wet ESP may potentially provide more efficient particulate control than a wet gas scrubber, with control efficiencies exceeding 99%.

4. Evaluate Most Effective Controls

While a wet ESP may be the most effective particulate control device, the cost is not economically feasible. According to facility calculations, the cost per ton of pollutant controlled for a wet ESP is more than \$88,000 per ton, based upon a 95% reduction in particulate. Therefore, the only remaining pollutant control option is a wet gas scrubber. The source currently employs a wet gas scrubber as a particulate control device.

5. Select BACT

RBLC entries for emission limits from wet gas scrubbers on FCCUs ranged from 0.3 to 1 lb/1000 lb coke. The existing WGS controls PM_{10} to below the 1.0 lb per 1,000 lb of coke burn-off NSPS limit. Therefore, the facility proposes to maintain the existing wet gas scrubber as BACT for PM_{10} at the current limit of 0.50 lb/1,000 lb of coke burn. This limit also matches those contained within the Consent Decree.

BACT for CO

1. Identify all Control Technologies

Emission control equipment that may be selected to control CO emissions from FCCU units include High Temperature Regeneration, Thermal Oxidation (CO Boiler), Catalytic Oxidation, and CO Combustion Promoter.

High temperature regeneration works by using excess oxygen and high operating temperatures to reduce carbon deposits, or coke, on the FCCU catalyst and to complete the combustion of CO. Thermal incineration uses an additional combustion unit to oxidize combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. Catalytic oxidation, similar to a thermal incinerator, involves heating a waste stream by a flame and then passing it through a catalyst bed that increases the oxidation rate more quickly. A CO combustion promoter method uses a platinum and/or palladium catalyst that is injected into full combustion regenerators only as needed to ensure that CO concentrations remain below 500 ppmv.

Searches of the RBLC were conducted to identify control technologies for the CO emissions from these units. Those entries that required add-on controls were mostly CO boilers, with a single entry for a CO combustion promoter. Other entries listed good combustion practice and high temperature regeneration.

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2. Eliminate Technically Infeasible Options

Catalytic oxidation, the facility states, is an infeasible control method for CO due to entrained particulate. Catalytic oxidation cannot be used on waste streams containing particulate due to potential catalyst fouling.

There is some question whether a CO combustion promoter is infeasible, though according to the facility, such a control option is not feasible in this case. Studies by another refinery indicate that CO combustion promoters may have no appreciable reduction in CO emissions. Also, the use of CO promoters can increase NO_x emissions as well.

3. Rank Remaining Control Technologies

Thermal incineration and high temperature regeneration remain technically feasible for CO reduction at the FCCU.

4. Evaluate Most Effective Controls

While thermal incineration can decrease CO emissions, the FCCU currently operates as a high temperature regeneration unit. The facility argues that no recognizable benefit will be gained by adding a CO boiler which would constitute additional combustion source. Addition of a CO boiler would increase fuel usage, thus creating more combustion pollutants – additional CO and NO_x.

The only remaining control technology or pollution prevention technique is high temperature regeneration.

5. Select BACT

The facility proposes high temperature regeneration as BACT for the FCCU. RBLC entries for this type of pollution prevention technique list few CO limits in units other than lb/hr and tpy. Entries in the RBLC for high regeneration in FCCUs list either lb/hr and tpy limits or the hourly NSPS limit of 500 ppm_{dv}. A single entry for an FCCU without add-on controls lists 50 ppm_{dv}. Other FCCUs which use thermal oxidation have limits exceeding 100 ppm_{dv} on an annual average.

The proposed CO BACT is high temperature regeneration and a proposed FCCU short-term flue gas emission limit consistent with the NSPS limit and Consent Decree limits of 500 ppm_{dv} and a 365-day rolling average limit of 100 ppm_{dv}.

SN-853-9

Particulate Matter (PM/PM₁₀)

1. Identify all Control Technologies

Emissions from the new cooling tower may include PM₁₀ emitted when water droplets containing dissolved solids are entrained in the air exiting the cooling tower. Entrained water droplets that exit the cooling tower system are termed "drift." The only known control technology for cooling towers are drift eliminators which reduce the droplets exiting the system.

All entries in the RBLC for cooling towers list drift eliminators as the control technology.

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2. Eliminate Technically Infeasible Options

The only remaining technology is the use of drift eliminators.

3. Rank Remaining Control Technologies

This step is not necessary due to the elimination of all other control technologies.

4. Evaluate Most Effective Controls

This step is not necessary due to the elimination of all other control technologies.

5. Select BACT

Therefore, the new cooling tower will be operated with drift eliminators to satisfy BACT requirements. The emissions rates estimated for the new cooling tower are consistent with those listed in the RBLC, though most entries list only an emission rate, not flow to the system. The only listed drift elimination was a single entry of 0.005%. The facility has chosen drift eliminators as control with drift of 0.005%.

Process Description

#1 Crude Unit:

This unit, which included the #1 Crude Topping Furnace (SN-801) and the #1 Crude Vacuum Furnace (SN-802) was removed from service.

#4 Crude Unit:

This unit is designed to separate approximately 65,000 BPD of light straight run gasoline and crude oil into various components of naphtha, gasoline, kerosene, diesel, gas oils and asphalt. Crude entering the unit is preheated using heat exchangers and hot rundown streams from the unit and flashed in the Pre-flash Column to produce gasoline and naphtha. The Pre-flash Column Reboiler (SN-803) is a NSPS Subpart J quality gas fired furnace used to maintain the temperature in the column. Bottoms from the column are heated in the fuel gas fired Atmospheric Topping Furnace (SN-804) prior to distillation at atmospheric pressure. The Atmospheric Column further separates the crude into naphtha, kerosene, diesel, and gas oil. Bottoms from the column are heated in the fuel gas fired Vacuum Furnace (SN-805) prior to vacuum distillation. The Vacuum Column separates the bottoms into gas oil and asphalt products.

#7 Fluid Catalytic Cracking Unit:

This unit is designed to convert approximately 20,000 BPD of gas oil from the refinery crude units and other sources into more useful products. Gas oil entering the unit is first heated to 675°F in the #7 FCCU Furnace (SN-808) which is fired with NSPS Subpart J quality gas and equipped with low NO_x burners. The hot oil is then contacted with a hot (approximately 1350°F) fluidized catalyst which causes the gas oil to crack into lighter products. The catalyst is then separated from the products in the Reactor and returned to the Regenerator. In the Regenerator, coke which has deposited on the catalyst is burned off and the catalyst is recycled. The hot flue gas leaving the Regenerator passes through two (2) sets of cyclones to remove any catalyst fines and is then used to produce steam in the waste heat boiler. The hot

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gases are then cooled to less than 500°F before exiting the #7 Catalyst Regenerator Stack (SN-809). The light products produced in the reactor are separated in the Fractionator Tower and used for various purposes. The FCCU Catalyst Regenerator Stack (SN-809) is equipped with a wet gas scrubber (WGS) for the control of SO₂ and PM₁₀ emissions.

#8 ULSD Hydrotreater:

The new #8 unit is designed to process diesel, kerosene, gas oil, or light cycle oil. This unit makes ultra low sulfur diesel quality fuel from diesel feedstock by reducing the sulfur content to 15 ppm as mandated by the Tier II diesel sulfur regulations. Light cycle oil, diesel, kerosene, or gas oil is heated in the new Tier II heater (SN-860) and then reacted with hydrogen in the reactor. Bottoms from the reactor flow through a high and low pressure product separator where the unreacted hydrogen is separated from the product and recycled to the reactor. The high pressure hydrogen gas stream is passed through an amine absorber to remove hydrogen sulfide gases from the system for sulfur removal in the sulfur recovery plant and/or NaHS unit. The liquid from the low pressure separator is passed through a stripper to remove any residual hydrogen sulfide before the desulfurized product is sent to storage.

#9 Unit:

This unit is designed to process approximately 16,000 BPD of naphtha from the crude unit and upgrade it into higher octane products. The process is divided into the Unifiner and Platformer sections.

In the Unifiner section, naphtha is heated in the #9 Hydrotreater Furnace/Reboiler (SN-810) and reacted with hydrogen over a cobalt/molybdenum catalyst to convert the sulfur in the naphtha stream to hydrogen sulfide. The Reactor effluent is passed through the Separator and Stripper to remove the hydrogen and hydrogen sulfide. The Stripper bottoms are sent to the Platformer section for further processing.

In the Platformer section, the Stripper bottoms are heated in the #9 Reformer Furnace (SN-811) and passed over a platinum/iridium catalyst in the Reactor where the naphtha molecules are restructured to form high octane compounds. The Reactor effluent is sent to two (2) Separators where hydrogen is separated from the platformate and recycled. The platformate is then sent to the Stabilizer, heated by the #9 Stabilizer Reboiler (SN-812), where the low molecular weight gases are removed and sent to the Reformer fuel gas system. The bottoms from the Stabilizer are sent to gasoline storage.

The Continuous Catalyst Regeneration (CCR) section of the Platformer allows the unit to increase its yield of high octane product due to increased activity from the catalyst. During a normal operating cycle, platforming catalyst deactivates due to coke laydown. The CCR is a continuous regeneration process that allows the coked catalyst to be continuously regenerated, therefore decreasing downtime required to maintain efficient operation. The #9 Continuous Catalyst Regenerator (SN-831) continuously burns off the coke deposit and restores catalyst activity, selectivity, and stability to essentially fresh catalyst levels.

As a result of the catalytic reforming process, high carbon content coke is deposited on the catalyst. This catalyst is then pneumatically conveyed from the reactor section to the regeneration section of the unit. Coke content on the spent catalyst is typically 4-5%, but at times may be as high as 12%. The catalyst is regenerated with a recirculated gas stream that is typically controlled between 0.9% and 1.1% oxygen. The coke on the catalyst is oxidized and the regenerated catalyst leaves the regeneration zone at less than

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0.2% coke. The catalyst then passes to subsequent zones in the regenerator to further condition the catalyst for use in the reactors. This gas leaving the regenerator is approximately 0.35% oxygen. Stoichiometrically, this equates to using approximately 50% excess oxygen in the regeneration process.

#10 Diesel Desulfurization Unit:

Upon completion of the Tier II Clean Fuels Project at the El Dorado Refinery, Lion Oil will utilize the #10 to desulfurize FCC gasoline. This unit will use a heavy cut of FCC gasoline as feed and will remove sulfur to levels that will yield overall concentrations of sulfur in Lion Oil's gasoline pool to 30 ppm to meet the Tier II Gasoline sulfur regulations. Heavy FCC gasoline is heated in the #10 hydrotreater furnace/reboiler (SN-813a) and then reacted with hydrogen in the reactor. Bottoms from the reactor flow to the product separator where the unreacted hydrogen is separated from the product and recycled to the reactor. The product then flows to a flash drum where most of the hydrogen sulfide that was formed in the reactor is flashed off and sent to the #17 and #18 units for treatment. The liquid from the flash drum is passed through a stripper to remove any residual hydrogen sulfide before the desulfurized product is sent to storage.

#11 Deasphaltizing Unit:

Asphalt produced directly from the #4 Crude Unit is processed through this unit to separate light hydrocarbons from the asphalt to yield a product suitable for catalytic cracking and at the same time, produce an asphalt with desirable properties. The #11 Unit is designed to process approximately 7,000 BPD of asphalt. Flux from the Crude Units is pumped into the top of the Extraction Tower and a propane/butane solvent is pumped into the bottom of the Extraction Tower. The two materials flow countercurrent to each other in the Extraction Tower. The solvent and deasphalted oil are then sent through a series of Evaporators and a Stripper where the solvent is distilled and condensed for recycle to the Extraction Tower. The deasphalted oil is used as feed to the Catalytic Cracker. Asphalt from the bottom of the Extraction Tower is heated in the #11 Deasphaltating Furnace (SN-814) and is passed through the Flash Tower and Asphalt Stripper to remove any residual solvent. The asphalt product is then sent to the Asphalt Plant where it is blended with other products.

Asphalt Plant Blowing Stills:

The asphalt plant stores, blends, and loads various grades of asphalt, primarily for roofing and paving uses. In addition, the plant has three (3) "blowing stills" where air is blown through asphalt to give it properties which are beneficial for producing specialty asphalts and roofing asphalts. Associated with these stills are three (3) NSPS Subpart J quality gas fired #16 Asphalt Blowing Furnaces (SN-825) which are used to maintain required temperatures during the blowing operation. The flue gas from the blowing stills is mostly air, mixed with some hydrocarbons. The flue gas is passed through a water scrubber to remove any globules of asphalt. Flue gas from the Scrubber enters the Fume Incinerator (SN-824) and any remaining hydrocarbons are destroyed. The hot flue gases from the Fume Incinerator are used to generate steam before being discharged to atmosphere.

#12 Distillate Hydrotreater:

This unit is a diesel and gas oil desulfurization unit with a design capacity to process 24,000 BPD. Its purpose is to produce on-road diesel quality fuel to meet the Clean Air Act standards. The light cycle oil from the #7 FCCU and the kerosene and diesel from the #4 Crude Unit is processed to reduce the sulfur

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content from approximately 2.0 weight percent to less than 0.05 weight percent. The unit is also used to hydrotreat gas oils to remove sulfur from the feed to the #7 FCCU.

The mixed feed flows through the heat exchange train and the #12 Distillate Hydrotreater Furnace (SN-842) before being reacted with hydrogen in the Reactor. The Reactor effluent flows through the heat exchange train with final cooling by an air fin cooler before flowing into the High Pressure Separator where the unreacted hydrogen is separated from the product and recycled to the Reactor. A small portion of the unreacted hydrogen stream is vented to the sour fuel gas system for treatment in the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit.

The liquid product is then flowed to the Low Pressure Separator where some of the hydrogen sulfide which was formed in the Reactor is flashed off and sent to the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit for treatment. The liquid from the Low Pressure Separator then flows through heat exchangers to the Stripper to remove any residual hydrogen sulfide. The liquid from the bottom of the Stripper is then cooled in the heat exchangers and the product air fin cooler before being sent to storage. The Stripper off gas is cooled in an air fin cooler and compressed before being mixed with the High Pressure Separator vent stream and the off gas from the Low Pressure Separator. This combined off gas stream is sent to the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit for treatment. The makeup hydrogen to the unit is supplied from two (2) compressors which also compress the recycled hydrogen and the Stripper off gas. These compressors are driven by electric motors. All emergency releases are routed to the existing refinery flare system.

Boilers:

Lion Oil has removed from service (6) fuel gas fired boilers which produced steam for the refinery, SN-815 through SN-820. Boilers #9, #10, and #11 (SN-815, SN-816, SN-817) are low pressure boilers each of which produce 60,000 pounds per hour of 150 psig steam. Boilers #12, #13, and #14 (SN-818, SN-819, and SN-820) are high pressure boilers each of which produce 100,000 pounds per hour of 275 psig steam. All of the boilers are normally fired with refinery fuel gas. Each of the existing boilers must be shut down by December 31, 2006. These existing boilers are being replaced by SN-821a, b, &c.

Lion is constructing three new boilers (SN-821a, SN-821b, SN-821c) to replace the existing boilers. The combined heat rating for the three new boilers will be 605 MMBtu/hr. These boilers will be fired with NSPS Subpart J quality gas. The boilers may burn fuel oil if fuel gas and natural gas are unavailable.

Sour Water Stripper:

The refinery generates numerous water streams from storage tanks and accumulators that contain high concentrations of hydrogen sulfide and ammonia. The Sour Water Stripper (SWS) is a trayed column which is used to steam strip the hydrogen sulfide and ammonia from the sour water streams before the water is discharged into the refinery waste water treatment system. The sour gases that are stripped from the water are directed to a Claus combustor/thermal reactor to recover sulfur in the form of hydrogen sulfide from sour water stripper offgas.

#18 Sodium Hydrosulfide Unit:

Several processes in the refinery produce gases which cannot be reprocessed and sold as liquid propane

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gas (LPG) or gasoline. These gases are generally methane, ethane, and hydrogen produced from catalytic cracking and the reforming of petroleum fractions. As these light fractions are separated from other heavier gases, hydrogen sulfide is separated with the light gases, making the gas sour. In order to use this gas as fuel for refinery furnaces and boilers, the hydrogen sulfide must be removed to prevent excess SO₂ emissions as the fuel is burned.

The #18 Sodium Hydrosulfide Unit is used to remove the hydrogen sulfide from the fuel gas. The unit removes hydrogen sulfide by contacting the gas with caustic soda to form sodium hydrosulfide which is sold to paper mills to be used as a delignifying agent. The fuel gas leaving the unit then flows to the #17 Unit where it is contacted with amine. This unit removes hydrogen sulfide to below the levels of 40 C.F.R. 60, Subpart J. The fuel gas is used as fuel in refinery furnaces and boilers. Any SO₂ emissions to the atmosphere are accounted for in the individual emissions for the boilers and furnaces and the Sodium Hydrosulfide Unit is not itself an emission source.

#17 Sulfur Recovery Plant:

The purpose of the Sulfur Recovery Plant is to recover sulfur, up to 100 LTD (long tons per day), as hydrogen sulfide from fuel gas and off-site natural gases from Great Lakes Chemical to meet refinery New Source Performance Standards (NSPS - Subpart J) for process fuel gases (less than 0.1 grains H₂S). In addition, Sour Water Stripper (SWS) off gas can be treated in the Sulfur Recovery Plant. The hydrogen sulfide is converted to a salable elemental sulfur product. The Sulfur Recovery Plant is also used to convert ammonia from SWS off gas to diatomic nitrogen and water. The Sulfur Recovery Plant can be divided into three (3) process units:

- a. Amine Unit consisting of two (2) amine contactors
- b. Sulfur Recovery Unit (SRU) (Claus)
- c. Tail Gas Treating Unit (TGTU)

Sour gas enters the primary amine unit where it is contacted with amine. The amine removes hydrogen sulfide and some carbon dioxide from the sour fuel gas stream. The sweetened gas exits the primary amine unit for distribution throughout the refinery. Hydrogen sulfide and carbon dioxide are stripped from the amine which creates a hydrogen sulfide rich gas (acid gas) stream. The acid gas is then sent to the SRU.

Acid gas from the primary amine unit and recirculated gas from the TGTU, along with SWS off gas, enter the SRU and go directly to the Claus Combustor/Thermal reactor. This is where approximately one-third of the hydrogen sulfide is converted to sulfur dioxide. Ammonia in the SWS off gas is converted to diatomic nitrogen and water at the Claus reactor. The hot vapor products leaving the thermal reactor make several passes through the sulfur condenser and the catalytic reactors. The sulfur condenser separates the condensed sulfur from the vapor and removes it to storage. The catalytic reactors further promote the reaction of hydrogen sulfide and sulfur dioxide to sulfur and water vapor. The remaining gas exits the SRU to the TGTU. The purpose of the TGTU is to recover sulfur from the SRU tail gas. The sulfur compounds are hydrogenated to hydrogen sulfide in the TGTU reactor. The vapor products from the reactor are then cooled and directed to the TGTU amine unit which operates much like the primary amine unit. The amine stripper off gas is recirculated to the SRU feed and the amine absorber off gas is directed to the Sulfur Recovery Plant catalytic incinerator (SN-844). The

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remaining low concentrations of hydrogen sulfide, carbon monoxide, and hydrogen are combusted in the incinerator.

Flares:

The refinery operates a High Pressure Flare (SN-822) and a Low Pressure Flare (SN-823) for disposing of excess combustible gases. These gases result from undetected leaks in operating equipment, upset conditions in the normal operation of a refinery where gases must be vented to avoid dangerously high pressure in operating equipment, plant start-ups, and emergency shutdowns. The flares are identical John Zink "smokeless" flares which use steam aspiration to control visible emissions. In addition to excess refinery gases, each flare burns approximately 1,406 scf/hr of natural gas for the pilot burners.

In conjunction with the flares, the refinery operates a flare gas recovery system (FGRS). The FGRS draws excess flare gases from the flare gas header upstream of a liquid seal vessel and recovers gas that would otherwise be burned in the flares. The capacity of the FGRS is automatically varied to maintain a positive pressure on the flare header upstream from the liquid seal vessel. Maintaining a positive pressure ensures that the air is not drawn into either the flare system or the flare gas recovery system. If the volume of the gas in the flare header exceeds the capacity of the FGRS, the excess gas will vent through the water seal on the FGRS to the flares.

Cellulose Fiber Baghouse:

The refinery operates an asphalt protective coatings unit. Cellulose fibers are received in bags and added to the system via a negative pressure hood and conveyor system. Any exhaust from the system is filtered through the Asphalt Protective Coating Baghouse (SN-807). Based on information submitted by Lion Oil in a letter dated July 25, 2002, this source has been moved to the insignificant activities list.

Truck Loading Racks:

The refinery operates several truck and rail loading racks. Products loaded range from asphalt to propane. The main truck loading rack is an automated bottom loading rack (SN-846) for loading transport trucks with all grades of gasoline and diesel. Emissions from all other loading racks are accounted for in the Heavy Oil Loading Racks (SN-847). Vapors generated at the gasoline/diesel loading rack during the loading operations are routed through a knock-out pot where any free liquids are recovered and the vapors are vented to a vapor recovery unit.

Gas Engine Compressors:

The refinery operates two (2) internal combustion gas compressor engines (SN-841 and SN-841A). The compressors operate on natural gas and are utilized in moving gases within refinery applications. The two JVG compressors (SN-839 and SN-840) have been converted from internal combustion to electrical power, and no longer generate any air emissions. The 8GTL compressor was converted to electric power as well. The KVG and SVG Compressors, SN-834, SN-835, SN-837, and SN-838, have been converted to electrical power and no longer generate air emissions. SN-841 will discontinue operations once the SN-841A unit is operational.

Hydrocarbon Storage Tanks:

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The refinery operates numerous hydrocarbon storage tanks which store products ranging from asphalt to propane.

Steam Superheater Furnace:

The refinery operates two (2) steam turbine driven gas compressors which consume 25,000 pounds per hour of superheated steam. The furnace operates on NSPS Subpart J quality gas and has a design heat input of 10.0 MMBtu/hr.

#5 Alkylation Unit:

There are two (2) 1,500 barrel (BBL) steel tanks which are used for storing 99% sulfuric acid which is used as a catalyst in this unit. The charge to this unit is approximately 6,000 BPD. The acid is diluted to 90% and then pumped to two (2) 2,000 barrel (BBL) spent acid tanks. Two (2) Acid Fume Scrubbers (SN-826 and SN-827) packed with polypropylene saddles are used to scrub any vapors which may be generated from the tanks during loading and transfer operations. These sources (SN-826 and SN-827) have been moved to the insignificant activities list.

Asphalt Rack Steam Heater:

Various grades of asphalt which are used for paving are produced at the refinery. A NSPS Subpart J quality gas fired package boiler rated at 10 MMBtu/hr (SN-828) is used to heat asphalt products during the truck loading operation.

#6 Hydrotreater/Isomerization Unit:

This unit has been installed due to EPA's lead phase down regulation. The unit upgrades light straight run naphtha from the crude unit into a higher octane gasoline. It consists of a hydrotreater section and a penex isomerization section. In the hydrotreater, light straight run naphtha from the crude units is heated in the #6 Hydrotreater Furnace/Reboiler (SN-806) and reacted with hydrogen over a nickel/molybdenum catalyst to convert the sulfur in the light straight run naphtha stream to hydrogen sulfide.

The reactor effluent is passed through the separator and stripper to remove hydrogen and hydrogen sulfide. The stripper bottoms are sent to the penex isomerization section for further processing. Here, the stripper bottoms are heated in the isomerization heater and passed over a platinum catalyst in the reactor where the light straight run naphtha molecules are restructured to form higher octane compounds. The reactor effluent is sent to a separator where hydrogen is separated from the isomerate and recycled. The isomerate is then sent to the stabilizer where the low molecular weight gases are removed through a caustic scrubber and sent to the refinery fuel gas system. The bottoms from the stabilizer are sent to gasoline storage.

Asphalt Tank Heaters:

The refinery operates forty-seven (47) asphalt tank heaters (SN-832) which are fired by NSPS Subpart J quality gas.

Wastewater Treatment Plant:

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This unit uses a combination of chemical, biochemical, and physical processes to remove pollutants from refinery wastewater before discharging into DeLoutre Creek. The main components of the unit are dual API separators, two (2) equalization tanks and pond, a dissolved air flotation (DAF) unit, a cooling tower, two (2) activated sludge bio-reactors, two (2) clarification tanks, sludge recycle equipment, an aerobic digester, and a sludge thickener. Final effluent filters assure a minimum level of suspended matter in the effluent discharged to DeLoutre Creek.

Final effluent cooling towers cool the effluent prior to discharge. Sludges generated at the Waste Water Treatment Plant are dewatered at the Sludge Management Facilities (SMF) prior to effluent disposal.

The facility is currently in the process of constructing a new system for the handling and treatment of process wastewater. This new system will allow for the segregation of process wastewater from refinery stormwater. VOC emissions from wastewater treatment at the facility should be greatly reduced once the new system is completed and operational. Once the new system is completed, the existing system will be converted to stormwater-only use.

Lime Silo:

Lime used in the SMF is stored in a lime silo. This silo is equipped with a baghouse (SN-845) which controls emissions during periods of filling. Based on information submitted by Lion Oil in a letter dated July 25, 2002, the Lime Silo Baghouse (SN-845) has been moved to the insignificant activities list.

Polymer Asphalt Letdown Facility:

This unit, which includes SN-850, is designed to produce a performance graded polymer modified asphalt binder for the asphalt paving industry. The unit consists of a refinery fuel gas-fired heater with a design nominal firing rate of 20 MMBtu/hr based on the HHV, a hot oil circulating pump, a heat exchanger, storage tanks, and loading racks. The hot oil circulates through coils in the storage tanks to maintain the final product in a fluid and transportable state. The heat exchanger is included in the hot oil system to keep the neat asphalt in a fluid state during the PMA blending operations.

Fugitive Emissions from Equipment Leaks:

Fugitive emission sources include leaks of hydrocarbon vapors from process equipment and evaporation of hydrocarbons from open areas, rather than a stack or vent. Fugitive emission sources include valves of all types, flanges, pump and compressor seals, wastewater collection, cooling towers, and oil/water separators.

Miscellaneous Operations:

Catalyst used in the #7 FCCU is stored in two hoppers, which exhaust through the #7 FCCU wet gas scrubber unit and are not emission sources. The hoppers are filled by "sucking" the catalyst into the hoppers. Each of the hoppers is equipped with eductors which reduce the pressure in the hoppers during the filling operation.

Table 8 - PSD Review History Summary:

PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
*Sources without old source numbers were previously unpermitted.		
37	T-3	1950
38	T-4	1953
40	T-11	1959
41	T-12	1955
42	T-14	1942
43	T-15	1942
44	T-16	1950
45	T-17	1940
46	T-18	1949
47	T-20 scheduled for removal	1945 2004
48	T-21 scheduled for removal	1945 2004
49	T-22	1953
50	T-23	1953
52	T-25	1940
54	T-27	1950
55	T-36	1953
56	T-39	1958
57	T-40	1940
58	T-41	2005
59	T-46	1933
60	T-48	1923
61	T-49	1923
62	T-50	1937
63	T-51	1940
65	T-54	1922
66	T-55	1923
67	T-56, Removed	1923
68	T-57, Removed	1949
69	T-58	1952
70	T-60, Removed	1923
71	T-61	1949

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PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
72	T-62	1949
73	T-63	1957
74	T-64	1957
75	T-65	1954
76	T-70	1935
77	T-71	1935
78	T-72	1950
79	T-73	1950
80	T-74	1950
81	T-76	1938
82	T-77	1945
84	T-80, Removed	1936
86	T-83, Removed	1938
87	T-84	1953
88	T-85	1954
90	T-89	1948
91	T-96	1940
92	T-97	1940
93	T-98	1940
94	T-99	1940
95	T-101	1922
96	T-102	1922
98	T-104	1923
99	T-105	1923
100	T-107	1923
103	T-110	1928
104	T-111	1936
105	T-112	2005
107	T-114	1923
108	T-115	1923
109	T-116	1923
110	T-117	1923
111	T-118	1944
112	T-119	1940
	T-120	1949
113	T-121	1949
114	T-122	1953
	T-123	1949
115	T-124	1959

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PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
116	T-125	1953
117	T-126	1953
118	T-128	1959
119	T-129	1937
120	T-145	1950
121	T-162	1951
122	T-165	1923
123	T-166	1923
124	T-167	1940
125	T-168	1940
126	T-170	1950
127	T-171	1950
128	T-173	1945
129	T-175	1940
130	T-176	1940
	T-180	1959
131	T-190	1940
	T-199	1957
132	T-200	1936
133	T-217	1964
134	T-219	1967
135	T-226	1936
136	T-228	1936
137	T-240	1953
138	T-241	1953
139	T-242	1953
140	T-243	1953
141	T-244	1953
142	T-245	1953
143	T-246	1953
144	T-247	1959
145	T-262	1938
146	T-263	1938
147	T-264	1938
148	T-265	1938
149	T-270	1941
150	T-271	1941
154	T-306	1952
155	T-310	1950

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PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
	T-311	1950
	T-312	1950
	T-313	1950
	T-314	1950
	T-315	1950
156	T-319	1950
157	T-320	1950
158	T-321	1950
159	T-322	1950
160	T-323	1950
162	T-325	1950
163	T-326	1950
164	T-327	1950
165	T-328	1950
166	T-329	1950
167	T-330	1950
168	T-331	1950
169	T-332	1950
170	T-333	1950
171	T-335	1950
	T-336	1950
172	T-337	1950
173	T-338	1950
174	T-339	1950
175	T-340	1961
176	T-348	1968
177	T-349	1968
178	T-350	1954
179	T-351	1954
180	T-352	1954
181	T-353	1954
182	T-354	1954
183	T-355	1959
184	T-356	1961
185	T-360	1957
186	T-361	1957
187	T-368	1966
188	T-371	1959
189	T-372	1959

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PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
191	T-410	1945
192	T-411	1945
193	T-412	1945
194	T-413	1945
	T-414	1945
195	T-429 demolished	1945 1999
	T-520	1950
	T-521	1950
196	T-524	1951
	T-525	1951
197	T-530	1951
	T-570	1959
01	801 shutdown	1930 1986
02	802 shutdown	1960 1986
07	807	1977
09	809	1973
13	813a	2005
16	816** shutdown	1945
17	817** shutdown	1945
18	818** shutdown	1952
19	819** shutdown	1952
20	820** shutdown	1958
23	823	1974
24	824	1977
25	825	1945/1946
	833	1959
	834 scheduled for removal	1942

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PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
	835 scheduled for removal	1942
	837 scheduled for removal	1958
	838 scheduled for removal	1958
	839	1959
	840	1959
	847	Pre-1950 ¹ Pre-1950 ² 1975 ³ Pre-1950 ⁴ Pre-1950 ⁵
	848	1973

**The previously permitted emissions for the #10, #11, #12, #13, and #14 Boilers, (SNs 816-820) were based upon the emission factors reported in the 1975 Second Edition of AP-42. An average emission factor of 175 lbs/10⁶ ft³ was used from the reported range of emission factors given for NO_x. The emission factor used to permit NO_x in this permit was based upon emission factors reported in the 1995 Fifth Edition of AP-42. The emission factor used for permitting NO_x is 280 lbs/10⁶ ft³.

¹ 111/219 West Truck Rack

² South Asphalt Plant Truck Rack

³ PMA Plant Truck Rack (formerly known as the Emulsion Plant Truck Rack)

⁴ Pumphouse Truck Rack

⁵ E & W Rail Car Rack

The following sources were installed or modified after the effective date of the PSD regulations; however, the emission increases did not exceed the significance levels and PSD review would not have been required.

Table 9 - Sources Installed After the Effective Date of PSD

PSD Review Sources Installed After the Effective Date of PSD			
Old Source Numbers	New Source Numbers	Year Installed	Associated Emission Increase
*Sources without old source numbers were previously not permitted.			
**Emission increase was determined by multiplying the lb/hr by 4.38.			
***These were the emissions permitted in Permit #868-AR-5.			

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PSD Review			
Sources Installed After the Effective Date of PSD			
83	T-78	installed 1950 replaced 1999	5.0 tpy VOC
89	T-88	1987	1.21 tpy VOC
97	T-103	1995	22.78 tpy VOC**
101	T-108 modified	1934 1982	4.38 tpy VOC**
102	T-109 modified	1934 1982	4.38 tpy VOC**
106	T-113 modified	1923 1995	4.38 tpy VOC**
	T-142	1982	4.38 tpy VOC**
	T-143	1982	4.38 tpy VOC**
151	T-272	1986	0.25 tpy VOC
152	T-273	1986	0.25 tpy VOC
153	T-274	1986	5.29 tpy VOC
161	T-324	1992	0.97 tpy VOC
190	T-384 modified	1974 1999	1.9 tpy VOC**
	T-432	1978	28.03 tpy VOC**
198	T-532	1981	35.98 tpy VOC
199	T-538	1989	0.25 tpy VOC
200	T-539	1989	0.25 tpy VOC
201	T-540	1987	0.25 tpy VOC
202	T-544	1991	1.11 tpy VOC
203	T-548	1993	19.01 tpy VOC
	T-549	1994	4.38 tpy VOC**
	T-550	1985	4.38 tpy VOC**
	T-551	1994	4.38 tpy VOC**
	T-552	1996	16.0 tpy VOC
	T-600	1994	4.38 tpy VOC**
	T-601	1994	4.38 tpy VOC**
	T-602	1994	4.38 tpy VOC**
	T-603	1995	4.38 tpy VOC**
	T-604	1994	4.38 tpy VOC**
	T-605	1996	4.38 tpy VOC**
	T-606	1996	4.38 tpy VOC**
	T-607	1990	4.38 tpy VOC**
	T-608	1987	4.38 tpy VOC**
	T-609	1995	4.38 tpy VOC**
	T-610	1980	4.38 tpy VOC**
	T-611	1995	4.38 tpy VOC**
	T-612	1995	4.38 tpy VOC**

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PSD Review Sources Installed After the Effective Date of PSD			
03	803	1979	2.2 tpy PM*** 4.4 tpy SO ₂ 30.7 tpy NO _x 0.5 tpy VOC 3.1 tpy CO
04	804	1991	9.2 tpy PM 24.5 tpy SO ₂ 39.42 tpy NO _x 2.63 tpy VOC 15.77 tpy CO
05	805	1996	2.2 tpy PM 39.5 SO ₂ 1.3 tpy VOC 29.5 tpy CO 39.5 tpy NO _x
06	806 modified	1958 1988	25.4 tpy SO ₂ 7.88 tpy PM 17.52 tpy NO _x 1.75 tpy CO
08	808	1979	2.2 tpy PM/PM ₁₀ *** 5.7 tpy SO ₂ 25.0 tpy NO _x 0.9 tpy VOC 4.0 tpy CO
11	811	1980	6.1 tpy PM/PM ₁₀ *** 0.5 tpy SO ₂ 1.8 tpy VOC 10.1 tpy CO 59.6 tpy NO _x ¹
22	822	1979	0.5 tpy PM/PM ₁₀ *** 117.8 tpy SO ₂ ² 3.5 tpy VOC 18.8 tpy CO 83.7 tpy NO _x ²
26	826	1982	0.5 tpy SO ₂ ***
27	827	1982	0.5 tpy SO ₂ ***
28	828	1987	0.5 tpy PM/PM ₁₀ *** 0.5 tpy SO ₂ 0.5 tpy VOC 0.9 tpy CO 7.9 tpy NO _x

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PSD Review			
Sources Installed After the Effective Date of PSD			
29	829	1987	0.5 tpy PM/PM ₁₀ *** 0.9 tpy SO ₂ 0.5 tpy VOC 0.9 tpy CO 7.5 tpy NO _x
30	830	1987	0.5 tpy PM/PM ₁₀ *** 0.5 tpy SO ₂ 0.5 tpy VOC 0.5 tpy CO 1.8 tpy NO _x
31	831	1991	1.75 tpy SO ₂ 1.75 tpy NO _x 4.82 tpy CO 48.2 tpy HCl
34	842	1993	2.2 tpy PM/PM ₁₀ 5.3 tpy SO ₂ 0.5 tpy VOC 3.5 tpy CO 17.5 tpy NO _x
35	843	1993	1.3 tpy PM 3.5 tpy SO ₂ 11.8 tpy NO _x 0.5 tpy VOC 2.2 tpy CO
36	844	1994	13.2 tpy PM/PM ₁₀ ³ 39.4 tpy SO ₂ 250 ppm SO ₂ 26.3 tpy NO _x 6.6 tpy VOC 35.5 tpy CO 2.2 tpy H ₂ S
32	832 (47) Asphalt Tank Heaters		15.8 tpy VOC
	Heats Tank SN	---	

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PSD Review Sources Installed After the Effective Date of PSD			
	T-24 T-39 T-40 T-41 T-56 T-78 T-99 T-107 T-111 T-118 T-219 T-348	1975 pre-1981 1988 1991 1989 1999 1991 1987 pre-1981 1987 1968 1968	
Continued	T-354 T-384 T-524 T-530 T-544 T-548	1956 1975 1986 1986 1991 1993	
33	836	1986	1.0 tpy PM/PM ₁₀ 1.0 tpy SO ₂ 1.0 tpy VOC 34.2 tpy CO 39.6 tpy NO _x Note: These are based on numbers in Permit #868-AOP-R0.
33	841	1981	1.0 tpy PM/PM ₁₀ 1.0 tpy SO ₂ 1.0 tpy VOC 58.3 tpy CO 79.7 tpy NO _x ⁴ Note: These are based on numbers in Permit #868-AOP-R0.
	845	1994	1.0 tpy PM/PM ₁₀
204	846	1980	Increase 727 tpy VOC Decrease 947 tpy VOC Net Change -220 tpy VOC The increase in emissions from the installation of the loading rack was offset by the removal of another loading rack. The modification took place while EPA Region VI was responsible for PSD review in the State of Arkansas.

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PSD Review			
Sources Installed After the Effective Date of PSD			
	847	1987 1989 1986	1.8 tpy VOC ^{5, 10} 1.0 tpy VOC ⁶ 1.0 tpy VOC ⁷
	849	1998	1.4 tpy PM ₁₀ 1.2 tpy SO ₂ 1.6 tpy VOC 11.6 tpy CO 19.2 tpy NO _x
Polymer Asphalt Let-Down Facility		All Sources Modified 1999	1.8 tpy PM ₁₀ ⁸ 3.2 tpy SO ₂ 15.8 tpy VOC 4.6 tpy CO 18.4 tpy NO _x
	T-24 T-384 T-385 T-386 T-387 T-553 T-554 847 850		1.8 tpy VOC 1.8 tpy VOC 1.8 tpy VOC 1.8 tpy VOC 1.8 tpy VOC 1.5 tpy VOC Inorganics 4.3 tpy VOC 1.0 tpy VOC
Sour Water Stripper Project		2000	1.1 tpy PM ₁₀ 1.1 tpy SO ₂ 1.4 tpy VOC 12 tpy CO 27.2 tpy NO _x
	T-7 816 817 818 819 820 844		
#4 Crude Unit Turnaround Improvements		2000	0.4 tpy PM ₁₀ 1.9 tpy SO ₂ 17.1 tpy VOC 6.5 tpy CO 3.9 tpy NO _x
	T-39 T-40 T-41 T-55		

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PSD Review Sources Installed After the Effective Date of PSD			
	T-84		
	T-121		
	T-122		
	T-219		
	T-368		
	803		
	804		
	805		
	814		
	847		

1. Construction commenced before the effective date of PSD. Additionally, subsequent increases in emissions were below PSD trigger limits.
2. Construction commenced before the effective date of PSD. This flare replaced two other high pressure flares.
3. This compressor engine replaced three existing gas air compressors.
4. 111/219 East Truck Rack
5. North Asphalt Plant Truck Rack
6. Lube Oil Truck Rack
7. The facility added a Polymer Asphalt Let-Down facility in 1999. Equipment affected by this project included the modification of tanks T-24, and T-384 through T-387, the installation of tanks T-553 and T-554, the increased use of the PMA Asphalt Truck Rack (SN-847) and the installation of the asphalt hot oil heater (SN-850). Tanks T-385 through T-386 were removed from service and permanently classified as out-of service during the early 1980's, but were put back into service for this project. The total permitted emissions for these sources is 1.8 tpy PM/PM₁₀, 3.2 tpy SO₂, 15.8 tpy VOC, 4.6 tpy CO, and 18.4 tpy NO_x (no netting performed). In order to process the PMA project as a minor modification, the north and south PMA racks were limited to a total throughput of 1.2 million bbl/year. Emissions from the North and South PMA Racks are included in the heavy oil loading rack PAL.
8. The Sour Water Stripper Project was reviewed to ensure that it did not trigger PSD at the Sulfur Recovery Plant. The actual increase in emissions that would affect the Sulfur Recovery Plant was less than 1.0 tpy SO₂. The Sulfur Recovery Plant is monitored by a CEMS unit which is used to demonstrate compliance with the NSPS standards and to demonstrate that the facility does not exceed the SO₂ emissions for SN-844.
9. There is a 99.1 tpy increase in permitted VOC emissions at the Heavy Oil Loading Rack (SN-847) from Permit #868-AR-7 to the Title V. This increase is not subject to PSD review. During the comment period for Permit #868-AR-5, was issued in 1996, the facility had attempted to update the emissions from this source based on updated information. No revisions or physical changes had occurred. A decision was made by the Department at that time to wait until the issuance of the Title V permit to make any updates to the emissions. The throughput limit for this loading rack has increased by 900 Mgal/yr from the previous permits. The only other change has been the methods of calculation.

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Regulations

The following table contains the regulations applicable to this permit.

Table 10 – Applicable Regulations

Regulation
Regulation 18 – <i>The Arkansas Air Pollution Control Code</i> , effective February 15, 1999
Regulation 19 – <i>The Arkansas Plan of Implementation for Air Pollution Control</i> , effective July 15, 2007
Regulation 26 – <i>Regulations of the Arkansas Operating Air Permit Program</i> , effective September 26, 2002
40 CFR Part 60 Subpart Db – <i>Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Appendix M)</i>
40 CFR Part 60 Subpart Dc – <i>Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*</i> (Appendix D)
40 CFR Part 60 Subpart J – <i>Standards of Performance for Petroleum Refineries*</i> (Appendix C)
40 CFR Part 60 Subpart Ka – <i>Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984*</i> (Appendix A)
40 CFR Part 60 Subpart Kb – <i>Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*</i> (Appendix B)
40 CFR Part 60 Subpart QQQ – <i>Standards of Performance for Petroleum Refinery Wastewater Systems*</i> (Appendix J)
40 CFR Part 60 Subpart UU – <i>Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture*</i> (Appendix H)
40 CFR Part 60 Subpart VV – <i>Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry*</i> (Appendix G)
40 CFR Part 60 Subpart GGG – <i>Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries*</i> (Appendix F)
40 CFR Part 61 Subpart FF – <i>National Emission Standards for Benzene Waste Operations*</i> (Appendix E)

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Regulation
40 CFR Part 63 Subpart CC – <i>National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*</i> (Appendix I)
40 CFR Part 63 Subpart UUU – <i>National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units</i> (Appendix O)
40 CFR Part 63 Subpart LLLLL – <i>National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing (Appendix P)</i> , effective May 1, 2006
40 CFR Part 63 Subpart ZZZZ - <i>National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (Appendix Q)</i> , effective June 15, 2004

* The Requirements of this permit are not intended to alter any applicable federal requirements.

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The following table is a summary of emissions from the facility. The following table contains cross-references to the pages containing specific conditions and emissions for each source. This table, in itself, is not an enforceable condition of the permit.

Table 11 – Emission Summary

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
Total Allowable Emissions		PM ₁₀	90.4	305.1	N/A
		SO ₂	179.5	544.7	
		VOC	11,616.6	10,008.1	
		CO	1,180.0	1,455.0	
		NO _x	283.8	635.3	
HAPS		Benzene*		67.9	N/A
		Biphenyl*		9.5	
		1,3 Butadiene*		5.1	
		Carbon Disulfide		4.4	
		Carbonyl Sulfide		4.5	
		Cresol (mixed isomers)*		14.0	
		Cumene*		10.2	
		Diethanolamine*		4.4	
		Ethyl benzene*		43.6	
		Hexane*		314.5	
		Naphthalene*		6.6	
		Phenol*		9.8	
		Toluene*		148.7	
		2,2,4 Trimethylpentane*		56.2	
		Xylene (mixed isomers)*		341.8	
		Chlorine		26.7	
		Hydrogen Chloride		48.6	
		Formaldehyde*		4.9	
		Perchloroethylene* (tetrachloroethylene)		7.1	
Air Contaminants		Ammonia		62.1	
		H ₂ SO ₄ (Sulfuric Acid)		88.3	
		H ₂ S		364.3	
		Particulate Matter		290.8	
801	#1 Crude Topping Furnace	Removed from Service			
802	#1 Crude Vacuum Furnace	Removed from Service			

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EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
803	Pre-flash Column Reboiler	PM ₁₀	0.4	1.3	71
		SO ₂	1.8	6.0	
		VOC	0.3	1.0	
		CO	2.6	8.7	
		NO _x	1.9	6.2	
804	#4 Atmospheric Furnace	PM ₁₀	2.8	9.3	71
		SO ₂	12.3	41.5	
		VOC	2.0	6.7	
		CO	14.6	49.2	
		NO _x	16.4	55.4	
805	No. 4 Pre-flash Column Reboiler	PM ₁₀	0.8	2.5	71
		SO ₂	3.3	11.2	
		VOC	0.6	1.8	
		CO	6.1	20.6	
		NO _x	3.5	11.6	
805N	#4 Vacuum Furnace	PM ₁₀	1.4	4.7	71
		SO ₂	6.3	21.1	
		VOC	1.0	3.4	
		CO	7.4	25.0	
		NO _x	6.5	21.9	
806	#6 Hydrotreater Furnace/Reboiler	PM ₁₀	1.0	4.4	71
		SO ₂	1.3	4.4	
		VOC	1.0	4.4	
		CO	3.2	10.9	
		NO _x	5.5	18.4	
807	Asphalt Protective Coatings Baghouse	Moved to Insignificant Activities List			
808	#7 FCCU Furnace	PM ₁₀	0.6	2.0	71
		SO ₂	2.7	8.9	
		VOC	0.5	1.5	
		CO	6.5	21.8	
		NO _x	2.8	9.3	
809	#7 Catalyst Regenerator Stack	PM ₁₀	7.5	32.9	80
		SO ₂	13.3	58.3	
		VOC	4.2	18.1	
		CO	116.0	101.9	
		NO _x	7.7	33.4	

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EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
810	#9 Hydrotreater Furnace/Reboiler	PM ₁₀	1.0	4.4	71
		SO ₂	3.1	10.3	
		VOC	1.0	4.4	
		CO	7.5	25.3	
		NO _x	12.7	43.0	
811	#9 Reformer Furnace	PM ₁₀	1.5	5.6	71
		SO ₂	6.8	25.2	
		VOC	1.1	4.4	
		CO	16.6	61.6	
		NO _x	20.2	74.7	
812	#9 Stabilizer Reboiler	PM ₁₀	1.0	4.4	71
		SO ₂	1.1	4.4	
		VOC	1.0	4.4	
		CO	2.7	9.0	
		NO _x	4.6	15.4	
813a	#10 Hydrotreater Furnace/Reboiler	PM ₁₀	0.6	2.0	71
		SO ₂	0.8	3.0	
		VOC	0.4	1.4	
		CO	2.0	7.2	
		NO _x	0.9	3.1	
814	#11 Deasphalting Furnace	PM ₁₀	1.0	4.4	71
		SO ₂	1.4	4.7	
		VOC	1.0	4.4	
		CO	3.4	11.6	
		NO _x	5.8	19.7	
816	#10 Boiler	Removed from Service			
817	#11 Boiler	Removed from Service			
818	#12 Boiler	Removed from Service			
819	#13 Boiler	Removed from Service			
820	#14 Boiler	Removed from Service			
821 (a,b,c total)	Refinery Boilers (fuel gas/natural gas firing)	PM ₁₀	7.8	---	88
		SO ₂	22.4	---	
		VOC	9.8	---	
		CO	474.2	---	
		NO _x	23.3	---	
821 (a,b,c total)	Refinery Boilers (fuel oil firing)	PM ₁₀	15.7	---	88
		SO ₂	37.3	---	
		VOC	20.0	---	
		CO	474.2	---	
		NO _x	66.6	---	

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EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
821 (a,b,c total)	Refinery Boilers (annual limits)	PM ₁₀	---	31.1	88
		SO ₂	---	81.3	
		VOC	---	39.1	
		CO	---	123.2	
		NO _x	---	58.0	
822 823	High and Low Pressure Flares	PM ₁₀	99 ¹	4.0	94
		SO ₂	484 ¹	19.6	
		VOC	842 ¹	34.1	
		CO	2,220 ¹	89.9	
		NO _x	612 ¹	24.8	
824	#16 Fume Incinerator	PM ₁₀	2.0	8.8	96
		SO ₂	23.1	101.5	
		VOC	4.1	18.0	
		CO	123.3	541.5	
		NO _x	2.0	8.8	
825	#16 Asphalt Blowing Furnaces	PM ₁₀	1.0	4.4	71
		SO ₂	1.3	4.4	
		VOC	1.0	4.4	
		CO	3.2	10.9	
		NO _x	5.5	18.4	
826	Acid Fume Scrubber	Moved to Insignificant Activities List			
827	Acid Fume Scrubber	Moved to Insignificant Activities List			
828	Asphalt Rack Steam Heater	PM ₁₀	1.0	4.4	71
		SO ₂	1.0	4.4	
		VOC	1.0	4.4	
		CO	1.1	4.4	
		NO _x	1.8	6.1	
830	Regenerant Furnace	PM ₁₀	1.0	4.4	71
		SO ₂	1.0	4.4	
		VOC	1.0	4.4	
		CO	1.0	4.4	
		NO _x	1.0	4.4	
831	#9 Continuous Catalyst Regenerator	PM ₁₀	2.0	8.8	100
		SO ₂	2.0	8.8	
		VOC	2.0	8.8	
		CO	2.6	11.4	
		NO _x	2.0	8.8	

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EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
832	47 Asphalt Tank Heaters	PM ₁₀	1.0	4.4	101
		SO ₂	4.3	14.7	
		VOC	1.0	4.4	
		CO	10.6	35.9	
		NO _x	12.9	43.6	
833	South XVG Compressor	Converted to electric power (no emissions)			
834	North KVG Compressor ³	Converted to electric power (no emissions)			
835	South KVG Compressor ³	Converted to electric power (no emissions)			
836	8GTL Compressor	Converted to electric power (no emissions)			
837	North 8SVG Compressor ³	Converted to electric power (no emissions)			
838	South 10 SVG Compressor ³	Converted to electric power (no emissions)			
839	East JVG Compressor	Converted to electric power (no emissions)			
840	West JVG Compressor	Converted to electric power (no emissions)			
841	G398TA Air Compressor	CO	3.1	13.6	103
		NO _x	3.1	13.6	
841A	G3512TA Air Compressor	CO	7.0	23.7	
		NO _x	4.7	15.8	
842	#12 Unit Distillate Hydrotreater	PM ₁₀	1.0	4.4	71
		SO ₂	2.2	7.4	
		VOC	1.0	4.4	
		CO	5.4	18.1	
		NO _x	5.3	17.8	
843	#12 Unit Stripper Reboiler Furnace	Removed from Service - 2005			71
844	Sulfur Recovery Plant Incinerator	PM ₁₀	12.0	52.7	71
		SO ₂	19.1	53.4	
		VOC	1.5	6.6	
		CO	8.1	35.6	
		NO _x	6.0	26.4	
845	Sludge Management Facility (Lime Silo Baghouse)	Moved to Insignificant Activities List			
846	Gasoline/Diesel Loading Rack	VOC	20.2	17.1	114
847	Heavy Oil Loading Racks	VOC	647.2	404.4	115

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EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
848	#7 FCCU Catalyst Hopper Vents	Emissions routed to the wet gas scrubber – does not directly vent			
849	Standby Diesel Crude Pump	PM ₁₀ SO ₂ VOC CO NO _x	1.4 1.2 1.6 12.2 20.2	1.4 1.2 1.5 11.6 19.1	117
850	Asphalt Hot Oil Heater	PM ₁₀ SO ₂ VOC CO NO _x	1.0 1.0 1.0 2.1 3.6	4.4 4.4 4.4 7.2 12.3	71
851	Wastewater Collection, Treatment, and Storage - old	VOC	900.0	3,294.0	118
851a	Wastewater Collection, Treatment, and Storage - new	VOC	26.1	85.9	118
852	Vacuum Distillation Unit	Emissions routed to fuel gas recovery system with 2003 Tier 2 facility modifications			
853	Cooling Towers	PM ₁₀ VOC	21.6 20.2	87.9 88.6	122
853a	#5 Cooling Tower	PM ₁₀ VOC	3.1 4.8	6.7 20.9	
853-9	#9 Cooling Tower	PM ₁₀ VOC	1.5 3.6	6.6 15.8	
854	Fugitive Equipment Leaks	VOC	679.8 ²	2,977.0	124
856	Tank Plantwide Applicability Limit	PM ₁₀ VOC CO	4.4 9,233.4 ² 207.2	1.4 2,934.2 65.9	132
857	Naptha Splitter Reboiler Heater	PM ₁₀ SO ₂ VOC CO NO _x	0.8 2.1 1.0 5.2 2.2	2.8 7.9 3.5 19.4 8.2	159
858f	Tier 2 Fugitives Annual VOC Bubble	VOC	---	41.3	124
858t	Tier 2 Tanks Annual VOC Bubble	VOC	---	322.5	132

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Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
859	#8 Cooling Tower (replaces #1 Cooling Tower)	PM ₁₀ VOC	2.9 5.3	12.8 22.9	122
860	ULSD Hydrotreater Heater	PM ₁₀ SO ₂ VOC CO NO _x	0.7 1.7 0.8 4.2 1.8	2.3 6.5 2.9 15.8 6.7	71
861	"New" Hydrogen Plant Heater(s)	PM ₁₀ SO ₂ VOC CO NO _x	2.2 6.1 2.7 25.9 8.1	7.1 20.5 9.0 50.0 27.3	71
862	Hot Oil Heater	PM ₁₀ SO ₂ VOC CO NO _x	0.4 1.6 0.3 3.8 3.3	1.2 5.3 0.9 12.8 11.0	71
863	Boiler Feedwater Pump	PM ₁₀ SO ₂ VOC CO NO _x	0.1 0.1 0.5 1.8 22.8	0.1 0.1 0.2 0.5 5.7	159
*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.					
**Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.					
¹ This figure represents a lb/day limit rather than a lb/hr limit. For the purposes of summarizing plantwide lb/hr emissions in this table, the lb/day limit for these sources was divided by 24 hours of operation. This figure is for illustrative purposes only, and these sources are not limited on an hourly basis.					
² The Tier 2 fugitives and tanks are subject to and included in all emission limits given for SN-854 and SN-856.					
³ These units will be converted to electrical power upon operation of the new Hydrogen Plant Heaters, SN-861.					

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Section III: PERMIT HISTORY

Permit #82-A was issued on November 19, 1971. This permit was for the construction of a sodium hydrosulfide plant to replace the existing sulfur recovery plant.

Permit #167-A was issued September 28, 1973. This permit approved a catalytic cracking facility by combining two catalytic cracking units into one.

Permit #252-A was issued in July 1974. This permit allowed the replacement of three uncontrolled flares with one John Zink STF-SA-24S smokeless flare.

Permit #167-A (modification) was issued on September 27, 1974. This permit allowed the continued operation of the #3 fluid catalytic cracking unit beyond the period designated in the original permit in order to allow time to increase the capacity of the #7 unit.

Permit #337-A was issued on May 28, 1976. This permit allowed the installation of a stripper to remove H_2S from the refinery wastewater stream with the off gas being treated by the existing sodium hydrosulfide unit.

Permit #338-A was issued on May 28, 1976. This permit allowed the installation of a scrubber-incinerator-waste heat boiler to control emissions from the Asphalt Plant.

Permit #423-A was issued on August 18, 1977. In this permit, the facility proposed to install a baghouse to control asbestos emissions from the protective coatings plant.

Permit #438-A was issued on November 18, 1977. This permit allowed the installation of a pre-flash column reboiler heater in order for the facility to meet the EPA's requirement to reduce lead in gasoline.

Permit #454-A was issued on March 24, 1978. This permit allowed the facility to replace the existing truck loading dock with a new truck transport terminal for gasolines, distillates, and LPGs.

Permit #337-A (modification) was issued in March 1978. There had been a delay in the modification of the hydrosulfide unit. This permit allowed the facility to operate the stripper prior to the upgrade.

Permit #520-A was issued on September 29, 1978. This permit allowed the installation of new and revamped platforming and unifying furnaces in order for the facility to meet the second part of the lead phasedown as required by the EPA.

Permit #252-A (modification) was issued in June, 1979. This permit allowed the replacement of two 16 inch flares with one 24 inch high pressure flare.

Permit #252-A (modification) was issued on November 20, 1981. This permit allowed the facility to replace a gasoline blending storage tank that had been condemned by increasing the use of the remaining tanks and reactivating out of service tanks. In order to comply with NSPS requirements Tank #124 was fitted with a secondary seal to the external floating roof. Tanks #108 and #109 were fitted with internal floating roofs.

Permit #868-A was issued on January 4, 1988. This permit served to consolidate all of the active

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permits held by this facility into one permit. It also permitted an asphalt loading heater and Isomerization Project as part of the lead phasedown required by the EPA.

Permit #868-AR-1 was issued on December 26, 1990. This modification allowed the installation of a topping furnace on the #4 crude unit.

Permit #868-AR-2 was issued on June 7, 1991. This modification allowed the installation of a continuous catalyst regeneration unit of a platforming unit.

Permit #868-AR-3 was issued on January 5, 1993. This modification permitted the installation of a 100,000 barrel asphalt storage tank.

Permit #868-AR-4 was issued on May 27, 1993. This modification permitted the installation of a distillate hydrotreater with a capacity of 20,000 barrels per day. The purpose of this modification was to make on-road diesel quality fuel to meet the Clean Air Act Standards.

Permit #1596-A was issued on January 31, 1995. This permit allowed the installation of a Sulfur Recovery Plant to produce elemental sulfur.

Permit #868-AR-5 was issued on August 12, 1996. This modification dealt with the installation of a new 50,000 barrel storage tank to replace an existing tank, installation of a 25,000 BPD vacuum furnace to replace an existing furnace, installation of a Sulfur Recovery Plant to replace the existing Sodium Hydrosulfide Unit, and documented the emissions from on-site storage tanks, product loading racks, and process fugitive emissions. Permits #868-AR-4 and #1596-A were consolidated.

Permit #868-AR-6 was issued on February 6, 1998. This minor modification was to install a standby diesel fueled crude pump in order for Tank #63 (SN T-63 for this permit, SN-73 of the old permit) to meet the standards of 40 C.F.R. 63, Subpart CC- *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*. The installation of the new pumping system allowed the tank to be taken out of crude oil storage service, and to be classified as a Group II storage vessel. This minor modification also allowed the facility to reduce VOC emissions from the tank, reduce crude oil inventories, and provide full emergency standby crude capacity in the event of a power failure.

Permit #868-AR-7 was issued on June 3, 1998. The purpose of this minor modification was to install an above ground storage tank (SN T-552) to replace an underground storage tank used to store gasoline for the company's motor fuel demands. The underground tank was owned by a company which provided fuel to Lion Oil.

Permit #868-AOP-R0 was issued on December 12, 2000 as the first operating permit for this facility as per the requirements of Regulation #26 and 40 C.F.R. § 70. In this permit, all of the tanks at the facility were bubbled under a PAL such that the facility has to comply with one VOC limit for the tank farm instead of a limit for each tank. Under this permit, the facility has permitted several sources that were previously unpermitted and increased several throughputs. The following minor modification and de minimis changes that were previously allowed were also included.

Minor modification submitted in September 1998: Permitted the Polymer Asphalt Let-Down Facility. The project consisted of installing a new gas fired hot oil system (SN-850), installation of two new tanks (SN's T-553 and T-554), modification of tanks (SN's T-24, T-384 through T-387)

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De minimis change submitted May 1999: Allowed the facility to replace the existing Sour Water Stripper with a new 400 gal/min Sour Water Stripper to minimize odors at the refinery. A new 20,000 barrel storage tank for the storage of sour water was also installed as part of the project.

De minimis change submitted October 1999: Allowed the facility to upgrade the #4 Crude Unit with new and refurbished equipment. The improvements included the installation of seven pumps and approximately 236 hydrocarbon valves with associated flanging and the removal of two pumps, 198 hydrocarbon valves and associated flanging. The improvements to the #4 Crude Unit also allowed the facility to produce intermediates that were previously purchased from outside sources. Associated equipment that will be affected by the changes at the facility are the #4 Pre-flash Column Reboiler (SN-03), #4 Atmospheric Furnace (SN-04), the #4 Vacuum Furnace (SN-05), the #11 Deasphalting Furnace (SN-14), the Asphalt Loading Racks (SN's 205-208), Asphalt Storage Tanks #39, #40, #41, #55, #84, #219, and #368, and Diesel Storage Tanks #121 and #122.

De minimis change submitted February 1999: Allowed the facility to construct a new 5,000 barrel asphalt storage tank (SN T-78) to replace the existing 2,500 barrel storage tank.

In previous permitting actions, the tank numbers did not coincide with the source numbers. In order to eliminate confusion and correct the problem, the source numbers for the facility were changed in this permitting action. Source numbers 01-700 are reserved for tank purposes. Source numbers for the other sources start at 801. See Appendix L.

Permit No. 868-AOP-R1 was issued to Lion Oil Co. on Dec. 5, 2003. This permit was the first modification to Permit #868-AOP-R0. It was issued as a part of the Permit Appeal Resolution between the Department and the facility. The following changes were made in this permit:

- a. The method of demonstrating compliance with the emission limits for the facility's tanks was changed to allow the facility to track refinery crude feed rate instead of conducting a monthly emissions inventory.
- b. A plantwide applicability limit was established for various other air pollutants in lieu of individual source emission limits.
- c. The effective dates of several of the testing conditions and opacity readings were modified or changed.
- d. Several equipment capacities were corrected or modified.
- e. The Plantwide Conditions were modified to clarify the difference between refinery fuel gas and desulfurized refinery fuel gas and which sources were able to burn which fuels.
- f. Clarifications were made regarding applicability of various regulations. Various wording changes and typographical and error corrections were made throughout the Permit.
- g. Various alternate operating scenarios were added to allow the facility flexibility in its operations. The frequency of monitoring the Btu content of the NSPS J quality gas was clarified. The Cooling Towers section (SN-853) was changed to include two cooling towers that were omitted from the previous permit. The emissions were updated to

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include particulate emissions.

- h. The Insignificant Activities List was updated.
- i. The Permit was updated to reflect the installation of a flare gas recovery system to recover refinery gases. The Permit was updated to reflect the installation of two additional 5,000 barrel storage tanks (T-382 and T-383) and one additional loading rack (PMA #2 Loading Rack).
- j. Two new gas oil tanks, one 2,000 bbl storage tank (T-19), and one 8,200 bbl storage tank (T-59) were added to the permit. These tanks were constructed to replace two older existing tanks (T-20 and T-21) which were removed from service. These two new tanks were incorporated into the facility-wide PAL for VOC emissions from tanks.
- k. One additional gas fired tank heater was permitted for installation in asphalt storage tank No. 78 (T-78). This new heater is rated at 0.68 MMBtu/hr.
- l. The installation of a new, enclosed process wastewater treatment system was permitted with this modification. This new system allows for the segregation of process wastewater from refinery stormwater. The existing wastewater treatment system will be converted to stormwater-only usage once the new system is completed. This change should result in significant decreases in VOC emissions from the wastewater treatment systems at the refinery.

Permit No. 868-AOP-R2 was issued to Lion Oil Co. on January 3, 2005. With this modification, the facility modified, or will be modifying several units, and installing new equipment in order to produce low-sulfur diesel fuel and gasoline to meet the new US EPA "Tier II" fuel sulfur requirements. The changes which occurred at the plant which are associated with the Tier II project are as follows:

- a. A new naphtha splitter was installed in the refining process following the #7 Fluid Catalytic Cracking Unit (FCCU).
- b. The existing #10 Diesel Hydrotreater was converted to treat FCC heavy naphtha.
- c. The #12 Unit Distillate Hydrotreater Stripper Reboiler Furnace (SN-843) was retrofitted with new piping to allow it to serve as the #10 unit Stripper Reboiler Furnace. After further evaluation, this heater will remain in its present service. There was no emissions change with this modification.
- d. New non-fired heat exchangers were installed in the #12 Unit to supply heat previously supplied by the #12 Distillate Hydrotreater Stripper Reboiler Furnace.
- e. A new diesel hydrotreater was installed (No. 8 ULSD Hydrotreater) to replace the #10 Diesel Hydrotreater and to produce Ultra-Low Sulfur Diesel (ULSD).
- f. A wet gas scrubber (WGS) was installed on the #7 FCCU Catalyst Regenerator Stack (SN-809) in order to reduce emissions of sulfur dioxide (SO₂) and particulate matter (PM/PM₁₀).

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- g. New equipment and piping was installed to handle wastewater from the No. 8 Unit and the WGS and to comply with NSPS QQQ where applicable.
- h. The catalyst utilized in the #9 CCR (SN-831) was changed to improve hydrogen production.
- i. The sulfur recovery capacity of the Sulfur Recovery Plant (SN-844) was increased to handle the increased sulfur removed from the fuel oil and gasoline.
- j. Three existing tanks (T-113, T-247, and T-372) were converted from diesel to FCC gasoline and heavy naphtha service. SN-113 was retrofitted with an external floating roof, and SN-247 and SN-372 were retrofitted with internal floating roofs.
- k. The diesel throughput of the following tanks increased: T-54, T-108, T-109, T-119, T-121, and T-122. No other changes have occurred at any of these tanks.
- l. Two new process heaters were installed. One at the #7 FCC Naphtha Splitter Reboiler, and one at the No. 8 ULSD Hydrotreater. These two heaters have been permitted as SN-857 and SN-860.
- m. A new emission bubble was added to the permit to simplify tracking of emissions associated with the Tier II clean fuels project. This bubble includes all emissions from fugitive sources associated with the Tier II project, as well as emissions from the tanks which were either modified, or experienced a throughput increase associated with the project. This source has been assigned SN-858. The tanks associated with the Tier II project were previously included in the refinery tanks bubble (SN-856). Permitted VOC emissions from SN-856 were decreased by the amount of the most recent available data for past actual emissions from the Tier II tanks.
- n. The No. 1 Cooling Tower was replaced with the new No. 8 Cooling Tower (SN-859). This change was necessary to provide for the increased process cooling water demands due to the new equipment associated with the Tier II changes. Although the No. 8 Cooling Tower has a higher cooling water handling capacity, permitted emissions will decrease with this change due to the use of drift eliminators for emissions control in the No. 8 tower.

Additionally, the following changes were made to the permit. These changes are not specifically associated with the tier II project, but were included in the permit at this time.

- a. Lion Oil proposed to lower permitted CO emissions from the No. 7 FCCU Catalyst Regenerator Stack (SN-809) to comply with provisions of the Consent Decree (CIV. No. 03-1028) between Lion Oil, the US EPA, and ADEQ. CO emissions from this source were required to comply with limits of 500 ppmvd at 0% O₂ (1-hour average) and 100 ppmvd at 0% O₂ (365-day rolling average). This resulted in a very substantial decrease in permitted CO emissions from this source (10,463.1 tpy decrease).
- b. A new non-contact condenser was installed on the Vacuum Distillation Unit (VDU). This change virtually eliminated VOC emissions from the VDU. These VOC emissions

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were previously routed through the No. 1 cooling tower, and included in SN-852. This changes resulted in a decrease in permitted VOC emissions of 242.1 tpy. Small quantities of VOC may continue to be emitted from the VDU in the form of fugitive equipment leaks. Such emissions are covered by SN-858, the Tier II fugitives and tanks emissions bubble.

- c. Catalytic converters and air/fuel ratio controllers were installed on the North 8 and South 10 SVG compressors (SN-837 and SN-838) and the East and West JVG compressors (SN-839 and SN-840). These controls were installed as a "supplemental environmental project" pursuant to paragraph 32(A) of the Consent Decree (CIV. No. 03-1028) between Lion Oil, the US EPA, and ADEQ. These controls were not installed pursuant to "BACT" or any portion of the NSR or PSD programs. The installation of these controls reduced emissions of NO_x and CO from these four compressor engines.
- d. A catalytic converter and air/fuel ratio controller was installed on the air compressor (SN-841) pursuant to BACT requirements and paragraph 16(B)(ii) of the Consent Decree (CIV. No. 03-1028). The installation of these controls reduced emissions of NO_x and CO from this compressor engine.
- e. A continuous emissions monitor (CEM) system was be installed on the #4 Atmospheric Furnace (SN-804). This system was installed in order to demonstrate compliance with an emission limit of 0.045 lb NO_x/MMBtu which was established pursuant to the Consent Decree (CIV. No. 03-1028) between Lion Oil Co., the US EPA, and ADEQ.
- f. Several new requirements were added to the permit to clarify regulatory applicability and other administrative issues as required by the Consent Decree (CIV. No. 03-1028) between Lion Oil, the US EPA, and ADEQ. No emissions changes resulted from these new permit conditions.
- g. As a result of the Consent Decree (CIV. No. 03-1028), three of the existing boilers (SN-818, 819, 820) were now identified as subject to the provisions of 40 CFR Part 60 Subpart J. Compliance with the NSPS requirements for H₂S concentration in the fuel gas resulted in a decrease in SO₂ emissions from these sources.

As a result of all of the modifications performed at the plant with this permit revision, overall permitted annual emissions limitations for the facility changed as follows: PM₁₀ decreased by 273.0 tpy, SO₂ decreased by 2,338.8 tpy, VOC decreased by 299.7 tpy, CO decreased by 10,620.0 tpy, and NO_x decreased by 89.2 tpy. There were no changes to any limits contained in the existing non-criteria pollutants bubble limits contained in this permit. The facility was required to continue to demonstrate compliance with these limits.

Permit No. 868-AOP-R3 was issued to Lion Oil Co. on November 28, 2006. This permit action serves to complete the renewal requirement of Regulation 26 and 40 CFR Part 70. This action also incorporated several modifications and minor modifications to the Title V Operating Air Permit for this facility. These modifications include the following changes.

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- a. The replacement of the five existing refinery boilers (SN-816 through SN-820) with three new boilers (SN-821a, b, c);
- b. The incorporation of the requirements of 40 CFR Part 60, Subparts Db and J and 40 CFR Part 63, Subpart DDDDD as they apply to the new boilers;
- c. The incorporation of the requirements of 40 CFR Part 63, Subpart UUU as they apply to the Fluid Catalytic Cracking Unit (FCCU) and the Sulfur Recovery Unit (SRU), and the Catalytic Cracking Unit (CCR).
- d. The removal of SN-843, the #12 Stripper Reboiler Heater;
- e. The installation of drift eliminators in the #5 Cooling Tower (SN-853a);
- f. The installation of a new 150,000 bbl asphalt storage tank (T-112) to be incorporated into the existing tank plantwide applicability limit (SN-856). This tank will be heated by a hot oil heater system (SN-862). This heater will be added to the existing tank heater bubble (SN-832);
- g. The replacement of the #10 Furnace/Reboiler (40 MMBtu/hr, SN-813) with a new process heater (17.9 MMBtu/hr, to be designated as SN-813a);
- h. An increase in the allowable cooling water flow rate through the #8 Cooling Tower (SN-859). There is no increase in the permitted emissions from the cooling tower with this change because past emissions were significantly over-estimated for this source.
- i. The replacement of 3,341 bbl asphalt storage tank with a new tank of equal dimensions. Emissions are not affected; 40 CFR Part 60, Subpart UU is triggered for the new tank; and,
- j. Increased annual emissions and annual heat input capacity permitted at the #9 Reformer Furnace (SN-811). Installation of a new Hydrogen Plant Heater (SN-861). These changes are an extension of the previously permitted and approved Tier II Fuels Project. The total project still meets minor modification applicability.

The primary change associated with this modification was the boiler replacement project. This project is required under the terms of the Consent Decree (CIV. No. 03-1028) reached by Lion Oil, ADEQ, and the US EPA. Under the terms of this agreement the new boilers must be in operation by January 1, 2007, and the five old boilers must be permanently shutdown prior to this date. The old boilers remain permitted for operation until December 31, 2006.

Other changes result from the renewal application. Various emission rates have been re-evaluated using updated emission factors for renewal purposes. Most changes are trivial, however; changes to the tanks PAL (SN-856) and fugitive PAL (SN-854) cause for a decrease in VOC emissions by several thousand tons per year. As a result of all the modifications and renewal updates, facility-wide permitted emission limitations have changed as follows: PM 0 tpy; PM₁₀ -295.6 tpy; SO₂ 1.6 tpy; VOC -5,138.7 tpy; CO 61.9 tpy; NO_x -7.7 tpy.

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Permit No. 868-AOP-R4 was issued to Lion Oil Co. on March 7, 2007. This permit revision incorporated the following changes:

- Routed the #7 FCCU Catalyst Hopper Vents, SN-848, to the wet gas scrubber of the #7 FCCU unit (SN-809).
- Increased short-term NO_x emission limits in lb/MMBtu on a 3-hour average basis based upon actual performance as demonstrated by a CEMS and performance tests.
- Increased the permitted annual emissions and annual heat input capacity of the Hydrogen Plant Heaters (SN-861) by installing two new, replacement units.
- Increased the permitted emissions at the Tier II Heaters, Naptha Splitter Reboiler Heater (SN-857) and ULSD Hydrotreater Heater (SN-860), by 0.3 tpy VOC , each respectively, and 0.1 tpy CO at SN-857.
- Decreased the permitted particulate emissions at the Tier II Heaters, SN-857 and SN-860, by -1.6 and -1.3 tpy, respectively.
- Installed a 150,000 bbl storage vessel for additional asphalt storage.
- Removed T-56, T-57, T-60, T-81, and T-83 from the list of permitted tanks.

Section IV: Emission Unit Information

SN-803 - #4 Pre-flash Column Reboiler
SN-804 - #4 Atmospheric Furnace
SN-805 - No. 4 Pre-flash Reboiler
SN-805N - #4 Vacuum Furnace
SN-806 - #6 Hydrotreater Furnace/Reboiler
SN - 808-#7 FCCU Furnace
SN-810 - #9 Hydrotreater Furnace/Reboiler
SN-811 - #9 Reformer Furnace
SN-812 - #9 Stabilizer Reboiler
SN-813a - #10 Hydrotreater Furnace/Reboiler
SN-814 - #11 Deasphalting Furnace
SN-825 - #16 Asphalt Blowing Furnaces
SN-828 - Asphalt Rack Steam Heater
SN-830 - Regenerant Furnace
SN-842 - #12 Unit Distillate Hydrotreater
SN-850 - Asphalt Hot Oil Heater
SN-857 - Naptha Splitter Reboiler
SN-860 - ULSD Hydrotreater Heater
SN-861 - Hydrogen Plant Heater
SN-862 - Hot Oil Heater

Source Descriptions

All sources in this grouping are subject to 40 C.F.R., Part 60, Subpart J-*Standards of Performance for Petroleum Refineries*.

SN-850 and SN-862 are subject to 40 C.F.R. 60, Subpart Dc-*Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units*.

SN-803 is a 40 MMBtu/hr reboiler (nominal design) used to maintain the temperature in the pre-flash column in order to separate crude oil into gasoline and naphtha. The reboiler is fueled by NSPS Subpart J quality gas. It was installed in 1979 and will be retrofitted with next generation, ultra low NO_x burners. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀. BACT for this source is good combustion practice.

SN-804 is a 280 MMBTU/hr source used to heat the bottoms from the pre-flash column in order to separate them into naphtha, kerosene, diesel, and gas oil. The furnace is fueled by NSPS Subpart J quality gas. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀, NO_x, and CO. BACT for this source is good combustion practice and next generation ultra low NO_x burners.

SN-805 is a 75 MM Btu/hr reboiler (nominal design). It was installed in 1996 and will be retrofitted with next generation, ultra low NO_x burners. On May 17, 2000, this source was tested for NO_x emissions using EPA Reference Method 7E pursuant to §19.702 of Regulation 19, and 40 C.F.R., Part 52, Subpart E. The test results submitted to the Department demonstrated compliance. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀. BACT for this

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source is good combustion practice.

SN-805N is a 142.2 MMBTU/hr (annual) source. The furnace will be fueled by NSPS Subpart J quality gas. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀, NO_x, and CO. BACT for this source is good combustion practice and next generation ultra low NO_x burners.

SN-806 is a 20 MMBtu/hr furnace (nominal design) used to raise the temperature of light straight run (LSR) to reaction. It is fueled with NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-808 is a 56 MMBtu/hr furnace (nominal design) used to heat gas oil. It is fueled by NSPS Subpart J quality gas. It was installed in 1979.

SN-810 is a 70 MMBtu/hr furnace (nominal design) used to heat naphtha. It is fueled NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-811 is a 170 MMBtu/hr furnace (nominal design) used to heat the #9 Unit Stripper bottoms. It is fueled by NSPS Subpart J quality gas. It was installed in 1980.

SN-812 is a 25 MMBtu/hr furnace/reboiler (nominal design) used to heat platformate in order to remove low molecular weight gases. It is fueled by NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-813a is a 17.9 MMBtu/hr furnace (nominal design) used to heat light cycle oil, diesel, kerosene, and gas oil. It is fueled by NSPS Subpart J quality gas. It was installed in 2005. This source utilizes ultra-low-NO_x burners for NO_x emissions control.

SN-814 is a 32 MMBtu/hr furnace (nominal design) used to heat asphalt from the bottom of the extraction tower. It is fueled by NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-825 is the combined emissions of three furnaces used to maintain the required temperature during the blowing operation. They have a combined heat input of 30 MMBtu/hr (nominal design) and are fueled by NSPS J quality gas. Two of the furnaces were installed in 1945. The other was installed in 1946. The blowing stills associated with the furnaces are not subject to 40 C.F.R., Subpart UU-*Standards of Performance for Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture* because they were constructed prior to the effective date.

SN-828 is a 10 MMBtu/hr boiler (nominal design) used to heat asphalt products during truck loading. It is fueled by NSPS Subpart J quality gas. It was installed in 1987.

SN-830 is a 1.8 MMBtu/hr furnace (nominal design). It is fueled by NSPS Subpart J quality gas. It was installed in 1987.

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SN-842 is a 50.0 MMBtu/hr furnace (nominal design). It is fueled by NSPS Subpart J quality gas. It was installed in 1993.

SN-843 was a 34.0 MMBtu furnace (nominal design). It was removed from service in 2005.

SN-850 is a 20.0 MMBtu/hr heater (nominal design) used to supply heat to the hot oil system which maintains the elevated temperatures of stored asphalt products so that the material will flow without solidifying. This source was installed in 1998. It is fueled by NSPS Subpart J quality gas. This source is subject to 40 C.F.R. 60, Subpart Dc-*Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units*.

SN-857 is rated at 53.4 MMBtu/hr. It is fueled by NSPS Subpart J quality gas.

SN-860 is rated at 43.6 MMBtu/hr. It is fueled by NSPS Subpart J quality gas.

At the completion of the Hydrogen Plant Project, this unit will be replaced with two, new units, SN-861, with a combined rating of 138.0 MMBtu/hr. Both are fueled by NSPS Subpart J quality gas.

SN-862 is a 35.2 MMBtu/hr fuel gas-fired hot oil heater (nominal design) and associated hot oil system for temperature control of asphalt tank T-112.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for the following sources shall be demonstrated by compliance with Subpart J and the fuel and Btu limits or with other available emissions data for these sources.
 [Regulation No. 19 §19.501 *et seq.* effective July 15, 2007 , and 40 CFR Part 52, Subpart E]

Table 12 – Subpart J Units Criteria Emissions

SN	Source Description	Pollutant	lb/hr	tpy
803	Pre-flash Column Reboiler	PM ₁₀	0.4	1.3
		SO ₂	1.8	6.0
		VOC	0.3	1.0
		CO	2.6	8.7
		NO _x	1.9	6.2
804	#4 Atmospheric Furnace	PM ₁₀	2.8	9.3
		SO ₂	12.3	41.5
		VOC	2.0	6.7
		CO	14.6	49.2
		NO _x	16.4	55.4
805	No. 4 Pre-flash Reboiler	PM ₁₀	0.8	2.5
		SO ₂	3.3	11.2
		VOC	0.6	1.8
		CO	6.1	20.6
		NO _x	3.5	11.6

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SN	Source Description	Pollutant	lb/hr	tpy
805N	#4 Vacuum Furnace	PM ₁₀	1.4	4.7
		SO ₂	6.3	21.1
		VOC	1.0	3.4
		CO	7.4	25.0
		NO _x	6.5	21.9
806	#6 Hydrotreater Furnace/Reboiler	PM ₁₀	1.0	4.4
		SO ₂	1.3	4.4
		VOC	1.0	4.4
		CO	3.2	10.9
		NO _x	5.5	18.4
808	#7 FCCU Furnace	PM ₁₀	0.6	2.0
		SO ₂	2.7	8.9
		VOC	0.5	1.5
		CO	6.5	21.8
		NO _x	2.8	9.3
810	#9 Hydrotreater Furnace/Reboiler	PM ₁₀	1.0	4.4
		SO ₂	3.1	10.3
		VOC	1.0	4.4
		CO	7.5	25.3
		NO _x	12.7	43.0
811	#9 Reformer Furnace	PM ₁₀	1.5	5.6
		SO ₂	6.8	25.2
		VOC	1.1	4.4
		CO	16.6	61.6
		NO _x	20.2	74.7
812	#9 Stabilizer Reboiler	PM ₁₀	1.0	4.4
		SO ₂	1.1	4.4
		VOC	1.0	4.4
		CO	2.7	9.0
		NO _x	4.6	15.4
813a	#10 Hydrotreater Furnace/Reboiler	PM ₁₀	0.6	2.0
		SO ₂	0.8	3.0
		VOC	0.4	1.4
		CO	2.0	7.2
		NO _x	0.9	3.1
814	#11 Deasphalting Furnace	PM ₁₀	1.0	4.4
		SO ₂	1.4	4.7
		VOC	1.0	4.4
		CO	3.4	11.6
		NO _x	5.8	19.7

Facility: Lion Oil Co.
 Permit No.: 868-AOP-R5
 AFIN: 70-00016

SN	Source Description	Pollutant	lb/hr	tpy
825	#16 Asphalt Blowing Furnaces	PM ₁₀	1.0	4.4
		SO ₂	1.3	4.4
		VOC	1.0	4.4
		CO	3.2	10.9
		NO _x	5.5	18.4
828	Asphalt Rack Steam Heater	PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	1.1	4.4
		NO _x	1.8	6.1
830	Regenerant Furnace	PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	1.0	4.4
		NO _x	1.0	4.4
842	#12 Distillate Hydrotreater Furnace	PM ₁₀	1.0	4.4
		SO ₂	2.2	7.4
		VOC	1.0	4.4
		CO	5.4	18.1
		NO _x	5.3	17.8
843	#10 Stripper Reboiler Furnace	Removed From Service		
850	Asphalt Hot Oil Heater	PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	2.1	7.2
		NO _x	3.6	12.3
857	Naphtha Splitter Reboiler	PM ₁₀	0.8	2.8
		SO ₂	2.1	7.9
		VOC	1.0	3.5
		CO	5.2	19.4
		NO _x	2.2	8.2
860	ULSD Hydrotreater Heater	PM ₁₀	0.7	2.3
		SO ₂	1.7	6.5
		VOC	0.8	2.9
		CO	4.2	15.8
		NO _x	1.8	6.7
861	Hydrogen Plant Heater(s)	PM ₁₀	2.2	7.1
		SO ₂	6.1	20.5
		VOC	2.7	9.0
		CO	25.9	50.0
		NO _x	8.1	27.3

Facility: Lion Oil Co.
 Permit No.: 868-AOP-R5
 AFIN: 70-00016

SN	Source Description	Pollutant	lb/hr	tpy
862	Hot Oil Heater	PM ₁₀	0.4	1.2
		SO ₂	1.6	5.3
		VOC	0.3	0.9
		CO	3.8	12.8
		NO _x	3.3	11.0

2. The facility shall not exceed the annual Btu limits for the sources set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Specific Condition #3. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]

Table 13 - Subpart J Units Annual BTU Limits

SN	Annual Limit (MMBtu/12 months)
803	351,360
804	2,459,520
805	658,800
805N	1,249,085
806	263,520
808	528,006
810	614,880
811	1,493,280
812	219,600
813a	173,045
814	281,088
830	15,811
842	439,200
843	298,656
850	175,680
857	469,066
860	382,982
861	1,212,192

3. Records of Btus shall be maintained on a twelve-month rolling basis for the sources listed in Specific Condition #2. These records shall be updated monthly. These records shall include the fuel combusted (natural gas or NSPS J quality gas) and heat duty (amount of gas x heating value). The permittee shall analyze the BTU content of the fuel gas on a monthly basis. The

records of BTU usages shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

4. The facility shall not exceed 5% opacity from the sources in this section. Compliance with this limit shall be demonstrated by burning pipeline natural gas or NSPS J quality gas with an H₂S concentration less than 1,500 ppmvd. If the H₂S concentration exceeds 1500 ppmvd, then the facility shall comply with Specific Condition #5. [§18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
5. During those times in which the H₂S content of the refinery fuel gas combusted on-site exceeds 1500 ppmvd, the facility shall conduct an opacity observation for those sources which are permitted to combust NSPS Subpart J quality gas. These observations shall be conducted by someone who is familiar with the visible emissions from these sources. Any sources which generate visible emissions during these periods shall be considered to be in violation of the 5% opacity standard for that source. Records of these observations shall be maintained on-site, and shall be made available to the Department upon request. These records shall indicate the date and time of the observation, the name of the person making the observation, whether or not any visible emissions are detected, and a list of any sources (by SN) for which visible emissions were noted. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
6. Under the terms of 40 C.F.R. Part 60 Subpart Dc-Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, SN-850 and 862 are affected facilities (see Appendices D and E). [§19.304 of Regulation 19 and 40 C.F.R. §60.40c]

In lieu of §60.48c(g), in which the owner or operator of each facility shall record and maintain records of the amounts of each fuel combusted during each day, the facility through a letter of approval from John R. Hepola, Chief, Air/Toxics and Inspection Coordination Branch, EPA to Thomas Rheame of the Arkansas Department of Environmental Quality dated February 9, 1999, may record and maintain records of the amounts of each fuel combusted during each month.

7. All sources listed in Specific Condition 1 are affected facilities under the provisions of 40 C.F.R. 60, Subpart J-*Standards of Performance for Petroleum Refineries*. As such, these heaters shall burn either pipeline quality natural gas and/or NSPS J quality gas. They are defined in the subpart as fuel gas combustion devices subject to the Subpart J requirements summarized in Plantwide Condition 11 (for the full regulation, see Appendix C). [§19.304 of Regulation 19 and 40 CFR §60.100]
8. The permittee shall operate the #4 Atmospheric Furnace (SN-804) such that NO_x emissions to the atmosphere do not exceed 0.045 lb/MMBtu based on a 3-hour average. [§19.501 of Regulation 19, §19.901 of Regulation 19, 40 CFR Part 52 Subpart E, and Paragraph 16(D) of the consent agreement between Lion Oil, the US EPA, and ADEQ]
9. The permittee shall operate a CEM system in the #4 Atmospheric Furnace (SN-804) exhaust stack for the purposes of monitoring NO_x emissions. The data from this monitor shall be recorded and compiled in order to demonstrate compliance with the 3 hour average 0.045 lb/MMBtu NO_x limit contained in Specific Condition #8. [§19.501 of Regulation 19, 40 CFR

Part 52 Subpart E, and Paragraph 16(D) of the Consent Decree (CIV. No. 03-1028) between Lion Oil, the US EPA, and ADEQ]

10. The fuel combusted in the #4 atmospheric furnace shall be sampled at least three times per calendar week in order to determine the higher heating value (HHV) and F-factor for the purposes of calculating the lb/mmBtu NO_x emissions using US EPA Method 19 as required by Specific Conditions #8 and #11. Records of the sample results shall be maintained on-site, and shall be made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]
11. All CEMs in use at the facility shall be operated in accordance with the Department's CEM Conditions (see Appendix K). The facility shall submit CEM data in accordance with the Department's conditions. CEM data shall be submitted in ppm for the refinery gas H₂S analyzers for SN's 803-806, 808, 810-814, 828-830, 842, and 850. The NO_x CEM data for SN-804 shall be submitted in lb NO_x/mmBtu. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
12. The permittee shall test PM/PM₁₀ emissions at SN-861, Hydrogen Plant Heaters. The testing shall be conducted within 180 days of operation commencement, in accordance with EPA Reference Methods 5 and 202. The PM₁₀ test will use either EPA Reference Methods 201A and 202 or 5 and 202. By using Method 5 and 202 for PM₁₀, the facility will assume all collected particulate is PM₁₀. During the test, the permittee shall operate the plant within 10 percent of the rated throughput capacity. If 90 percent of the rated throughput capacity cannot be achieved, the facility shall be limited to 10 percent above the actual tested throughput. [§18.1002 of Regulation 18 and A.C.A. §8-4-203 as referenced by 8-4-304 and §8-4-311]
13. Before operation of the new Hydrogen Plant Heaters, SN-861, the facility must permanently remove from service and no longer operate the following units in this section: the old Hydrogen Plant Heater units, SN-861a. These units provided emission limit offsets to keep the Hydrogen Plant Project below the PSD significance level. [Regulation No. 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]
14. The permittee shall demonstrate through an initial test NO_x emission rates no greater than 0.035 lb/MMBTU at SN-805 and SN-803 to demonstrate that an actual decrease in actual emissions occurred and thus, exempting the source from BACT for NO_x. The initial test shall take place 180 days after retrofit of these sources. Testing shall be performed in accordance with EPA Reference Method 7E or other pre-approved test method. At the time of testing, the permittee shall operate the source at least within 10% of its the maximum rated capacity. [§19.702 of Regulation #19, and 40 CFR Part 52 Subpart E]
15. The permittee shall demonstrate through an initial test CO emission rates no greater than 0.0625 lb/MMBTU at SN-805 and 0.0495 lb/MMBTU at SN-803 to demonstrate that an actual decrease in actual emissions occurred and thus, exempting the source from BACT for CO. The initial test shall take place 180 days after retrofit of these sources. Testing shall be performed in accordance with EPA Reference Method 10 or other pre-approved test method. At the time of testing, the permittee shall operate the source at least within 10% of its the maximum rated capacity. [§19.702 of Regulation #19, and 40 CFR Part 52 Subpart E]

Facility: Lion Oil Co.
 Permit No.: 868-AOP-R5
 AFIN: 70-00016

BACT Requirements

16. The following limitations and control technology are BACT for the following sources.
 [§19.901 of Regulation 19 and 40 CFR Part 52, Subpart E]

Table 14 – Process Heater BACT Limits

Combustion Source	Pollutant	Control Technology	BACT Limit lb/MMBtu (3-hour average)
Current #4 Pre-Flash Column Reboiler (SN-803)	PM ₁₀	Good Combustion Practice	0.0075
Converted #4 Pre-Flash Column Reboiler (SN-805)	PM ₁₀	Good Combustion Practice	0.0075
No. 4 Atmospheric Furnace (SN-804)	PM ₁₀	Good Combustion Practice	0.0075
	NO _x	Existing NGULNB	0.045
	CO	Good Combustion Practice	0.040
New No. 4 Vacuum Furnace (SN-805N)	PM ₁₀	Good Combustion Practice	0.0075
	NO _x	New NGULNB	0.035
	CO	Good Combustion Practice	0.040

17. The permittee shall demonstrate compliance with the particulate BACT limits for SN-803, SN-804, SN-805, and SN-805N by the use of NSPS quality gas and the opacity limits of Specific Condition 4. [§19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]
18. The permittee shall demonstrate compliance with the CO BACT limit for SN-804 and SN-805N by initial and periodic testing every five years thereafter. The compliance with the CO BACT limits in Table 15 shall be based upon a 3-hour average. The initial test shall take place 180 days after permit issuance. Testing shall be performed in accordance with EPA Reference Method 10 or other pre-approved test method. At the time of testing, the permittee shall operate the source at least within 10% of the maximum rated capacity. [§19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]
19. The permittee shall demonstrate continuous compliance with the NO_x BACT limit in Table 16 for SN-804 through use of a CEM as already required by Specific Condition 9. [§19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]
20. The permittee shall demonstrate compliance with the NO_x BACT limit in Table 17 for SN-805N by initial and periodic testing every five years thereafter. The initial test shall take place 180 days after permit issuance. Testing shall be performed in accordance with EPA Reference Method 7E or other pre-approved test method. At the time of testing, the permittee shall operate the source at least within 10% of the maximum rated capacity. [§19.901 of Regulation #19, and 40 CFR Part 52 Subpart E]

SN-809 - #7 FCCU Catalyst Regenerator Stack

Source Description

SN-809 is the exhaust stack from the catalyst regenerator. Hot flue gas leaving the regenerator passes through three sets of cyclones to remove catalyst fines and then is used to produce steam in the waste heat boiler before exiting the stack. This source was installed in 1973. Previously permitted source, SN-848, the vent system for two storage bins used to store catalyst in the catalytic cracking process, has been routed to the wet gas scrubber of the #7 FCCU unit.

The #7 FCCU was modified in 2004 to install a wet gas scrubber for the control of PM₁₀ and SO₂ emissions. Simultaneous with the installation of the scrubber, the facility also accepted a limit of 500 ppm_{dv} (1-hour average) and 100 ppm_{dv} (365-day rolling average) as required by the Consent Decree (CIV. No. 03-1028) reached between Lion Oil, the US EPA, and ADEQ. CEMs were installed to monitor the stack concentrations of SO₂, CO, and O₂.

BACT Review

This source underwent a BACT review for particulate and CO as a result of the refinery expansion of the R5 permit. BACT was demonstrated to be similar controls and emission limits as those defined by the Consent Decree.

Regulations

As of December 31, 2004, the Fluid Catalytic Cracking Unit (FCCU) is subject to 40 C.F.R., Part 60, Subpart J-*Standards of Performance for Petroleum Refineries*.

The Fluid Catalytic Cracking Unit (FCCU) is subject to 40 C.F.R., Part 63, Subpart UUU-*National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units*.

CAM (40 CFR Part 64) parametric monitoring is not required for this unit at this time due to its status as an existing unit, as well as the presence of CEM systems in the FCCU exhaust stack.

Specific Conditions

21. The permittee shall not exceed the emission rates set forth in the following tables. The permittee shall comply with the emission limits contained in the table below. Compliance with these limits shall be demonstrated by compliance with the throughput limits, monitoring requirements for this source or with other available emissions data for these sources. [§19.501 of Regulation 19 et seq., and 40 C.F.R., Part 52, Subpart E]

Facility: Lion Oil Co.
 Permit No.: 868-AOP-R5
 AFIN: 70-00016

Table 18 - #7 FCCU Catalyst Regenerator Stack Criteria Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
809	#7 Catalyst Regenerator Stack	PM ₁₀	7.5	32.9
		SO ₂	13.3	58.3
		VOC	4.2	18.1
		CO	116.0	101.9
		NO _x	7.7	33.4

22. The facility shall not exceed 20% opacity from this source. Compliance with this condition will be demonstrated by compliance with 40 CFR Part 60 Subpart J, the operation of the wet gas scrubber (WGS), and compliance with any alternative monitoring provision approved for this source by the US EPA. [§18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
23. On and after December 31, 2004, the FCCU exhaust shall meet the following outlet emissions limitations. [§19.501 et seq., 40 CFR Part 52 Subpart E, and Paragraphs 12(B), 13(B), and 14(B) of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA]
 - a. For SO₂:
 - i. No more than 25 ppmvd based on a 365-day rolling average, corrected to 0% oxygen.
 - ii. No more than 50 ppmvd based on a 7-day rolling average, corrected to 0% oxygen
 - iii. Exceptions to the SO₂ limits above occur during periods of startup and shutdown of the FCCU, and Malfunction of the WGS, provided that good air pollution control practices are instituted during such events.
 - b. For PM:
 - i. No more than 0.5 pounds of particulate matter (PM) per 1000 pounds of coke burned, on a 3-hour average basis except during periods of startup and shutdown of the FCCU, and Malfunction of the WGS, provided that good air pollution control practices are instituted during such events.
 - c. For CO:
 - i. 500 ppmvd corrected to 0% O₂, over a 1-hour averaging period.
 - ii. 100 ppmvd corrected to 0% O₂ as a rolling 365-day average.
 - iii. Exceptions to the CO limits above occur during periods of startup, shutdown, and Malfunction of the FCCU, provided that good air pollution control practices are instituted during such events.

Facility: Lion Oil Co.
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AFIN: 70-00016

24. On and after December 31, 2004, the permittee shall use a NOx CEMS to monitor performance of the FCCU, and subsequently, the Lo Tox System, and to report compliance with the terms and conditions of the Consent Decree (CIV. No. 03-1028). [§19.702, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, 40 CFR §70.6, and Paragraph 11(F) of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA]
25. On December 31, 2004, the FCCU became an affected facility under the terms of 40 CFR Part 60 Subpart J – Standards of Performance for Petroleum Refineries. The requirements of this subpart as they apply to this source are summarized below. [§19.304 of Regulation 19 and 40 CFR §60.100 and Paragraph 15 of the Consent Decree (CIV. No. 03-1028)]
 - a. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain particulate matter (PM) in excess of 2.0 lb/ton of coke burn-off in the catalyst regenerator. [§60.102(a)(1)]
 - b. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which exhibit an opacity greater than 30% except for one six-minute average opacity reading in any one hour period. [§60.102(a)(2)]
 - c. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain carbon monoxide (CO) in excess of 500 ppmvd. [§60.103(a)]
 - d. The permittee shall operate an add-on control device (WGS) to reduce SO₂ emissions to the atmosphere from the #7 FCCU Catalyst Regenerator Stack (SN-809) to a level below 50 ppmvd. Compliance with this limit shall be determined daily on a rolling 7-day basis. A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days. [§60.104(b)(1), 60.104(c), and §60.104(d)]
 - e. Continuous emission monitoring (CEM) systems shall be installed, certified, calibrated, maintained, and operated in the #7 FCCU Catalyst Regenerator Stack (SN-809) by the permittee as summarized below.
 - i. Lion Oil shall make CEMS data available to EPA upon demand as soon as practicable.
 - ii. The permittee has applied for approval from the US EPA for an alternative monitoring plan to demonstrate compliance with the opacity limit pursuant to Subpart J. If the administrator grants approval of this request, then the facility shall operate in compliance with the plan at all times, and a copy of the approval letter, as well as the alternative monitoring plan, shall be maintained along with this permit at the facility. If approval of the alternative monitoring plan is not granted, then the facility shall install a continuous opacity monitoring (COM) system in accordance with the requirements of Subpart J. [§60.105(a)(1)]
 - iii. A CEM system shall be installed for the continuous monitoring and recording of the concentration by volume (dry basis) of CO emissions to the atmosphere from

the #7 FCCU Catalyst Regenerator Stack. The span value for this system shall be 1,000 ppm CO. [§60.105(a)(2)]

- iv. A CEM system shall be installed for the continuous monitoring and recording of the concentration by volume (dry basis) of SO₂ emissions to the atmosphere from the #7 FCCU Catalyst Regenerator Stack (SN-809). The span value for this system shall be 100 ppm SO₂. [§60.105(a)(9)]
- v. A CEM system shall be installed for the continuous monitoring and recording of the concentration by volume of oxygen (O₂) in the #7 FCCU Catalyst Regenerator Stack (SN-809). The span value for this system shall be 10 percent. [§60.105(a)(10)]
- vi. The SO₂ and O₂ CEM systems operated in the #7 FCCU Catalyst Regenerator Stack (SN-809) shall be operated and data recorded during all periods of operation of the FCCU including periods of startup, shutdown, or malfunction, except for CEM system breakdowns, repairs, calibration checks, and zero and span adjustments [§60.105(a)(11)]
- vii. The permittee shall use the following procedures to evaluate the SO₂ and O₂ CEM systems operated in the #7 FCCU Catalyst Regenerator Stack (SN-809).
 - 1. Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the §60.13(e) performance evaluation. [§60.105(a)(12)(i)]
 - 2. Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drifts. [§60.105(a)(12)(ii)]
- viii. For the purposes of complying with the 50 ppmvd SO₂ emission limit, when emission data are not obtained because of CEM system breakdowns, repairs, calibration checks, and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in a least 22 out of 30 rolling successive calendar days. [§60.105(a)(13)]
 - 1. The test methods as described in §60.106(k);
 - 2. A spare CEM system; or
 - 3. Other monitoring systems as approved by the Administrator.
- ix. The average coke burn-off rate (tons per hour) shall be recorded daily for the #7 FCCU Catalyst Regenerator. [§60.105(c)]
- x. For the purpose of reports under §60.7(c), periods of excess emissions that shall be determined and reported are defined as follows: [§60.105(e)]

1. For Opacity (only applies if COM is used): All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the COM system exceeds 30 percent.
 2. For CO: All 1-hour periods during which the average CO concentration measured by the CEM system exceeds 500 ppmvd corrected to zero percent O₂.
- f. The permittee shall record and maintain the following information pertaining to the SO₂ monitoring requirements for the #7 FCCU Catalyst Regenerator Stack (SN-809). [§60.107(b)]
- i. All data and calibrations from the SO₂ CEM system, including the results of the daily drift tests and quarterly accuracy assessments required under Appendix F, Procedure 1;
 - ii. Measurements obtained by supplemental sampling for meeting minimum data requirements; and
 - iii. The written procedures for the quality control program required by Appendix F, Procedure 1.
- g. The permittee shall submit a report on the SO₂ CEM system which contains all of the information required by §§60.107(c) and (d). This report shall be submitted to the Department in accordance with the Department CEM Conditions (Appendix K). [§§60.107(c), (d), and (e)]
- h. The owner or operator of the facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. [§60.107(f)]
26. All CEMS shall be operated in accordance with the Department's CEM Conditions. The facility shall submit CEM data in accordance with the Department's standards. A copy of these standards has been attached as Appendix K. [§19.703 of Regulation 19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
27. SN-809 (the FCCU) is an affected facility under the terms of 40 C.F.R., Part 63, Subpart UUU-National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. The applicable requirements of this subpart are summarized in Plantwide Condition 12. [§19.304 of Regulation 19 and 40 CFR §63.1561]

BACT Requirements

28. The following limitations and control technology are BACT for the #7 FCCU Catalyst Regenerator. With the addition of Specific Condition 29, the permittee shall continue to demonstrate compliance with these limits according to the provisions already contained within Specific Conditions 23, 25, and 26. [§19.901 of Regulation 19 and 40 CFR Part 52, Subpart E]

Table 19 - #7 FCCU Catalyst Regenerator BACT Limits

Pollutant	Emission Limit	Compliance Demonstration Method	Control Technology
Filterable PM ₁₀	0.50 lb/1,000 lb of coke burn-off	EPA Reference Method 5B	Wet Gas Scrubber
CO	100 ppmdv (365-day rolling average)	CO CEMS	High Temperature Regeneration
	500 ppmdv (1-hr average)		

29. The permittee shall test particulate emissions at the #7 FCCU Catalyst Regenerator Stack (SN-809) within 180 days of the start of normal operations after completion of the expansion project in order to develop a PM₁₀ BACT limit including both filterable and condensable particulate. The testing shall be conducted in accordance with EPA Reference Method 5B and Method 202. During the test, the permittee shall operate the source within 10 percent of the maximum coke burn rate of 15,000 lb/hr. The permittee shall repeat the particulate testing using Methods 5B and 202 every five years after the initial performance tests. [§19.901 and §19.702 of Regulation 19 and 40 CFR Part 52, Subpart E]
30. Within 60 days after the completion of these initial performance tests, the permittee shall submit the results of the performance tests along with a permit application which proposes a final PM₁₀ BACT limit including both filterable and condensable particulate as measured by Methods 5B and 202. The proposed final emission limit shall be based on actual performance of the FCCU as demonstrated by the performance tests and shall be low enough to ensure proper operation of the PM₁₀ control technology and high enough to ensure a reasonable certainty of compliance. [§19.901 of Regulation 19 and 40 CFR Part 52, Subpart E]

ALTERNATE OPERATING SCENARIO - FCCU PORTABLE AIR COMPRESSORS

During periods of startup, shutdown and/or malfunction, or for purposes of conducting scheduled or emergency maintenance on the fluid catalytic cracking unit when the electric air compressors are not operating, Lion Oil may utilize portable, diesel-fired air compressors.

Specific Conditions

31. The permittee shall not operate the portable compressors for more than 1,560,000 horsepower-hours on an annual basis. [§19.501 of Regulation 19, et seq., and 40 C.F.R., Part 52, Subpart E]
32. Lion Oil will record the hours of operation of the air compressors, on a twelve-month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-844 - SRP Sulfur Recovery Plant Incinerator

Source Description

The Sulfur Recovery Plant Incinerator is a 20.0 MMBtu/hr incinerator used to incinerate gases from the sulfur recovery plant. It is fueled by pipeline quality natural gas. It was installed in 1994. The incinerator is used to control emissions from the 3 stage sulfur recovery unit (SRU) which is also subject to Subpart J. The SRP is rated at 120 long tons per day (LTD).

Specific Conditions

33. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for SN-844 shall be demonstrated by compliance with Subpart J, the fuel and Btu limits for these sources or with other available emissions data for these sources.
 [Regulation No. 19 §19.501 and 40 CFR Part 52, Subpart E]

Table 20 - SRP Sulfur Recovery Plant Incinerator Criteria Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
844	Sulfur Recovery Plant Incinerator	PM ₁₀	12.0	52.7
		SO ₂	19.1	53.4
		VOC	1.5	6.6
		CO	8.1	35.6
		NO _x	6.0	26.4

34. Any emissions to the atmosphere from any Claus sulfur recovery plant using an oxidation control system or a reduction control system followed by incineration shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated by SO₂ emissions data recorded per Subpart J (see Appendix C). [§19.304 of Regulation 19 and 40 C.F.R. §60.104(a)(2)(i)]

Table 21 - SRP Sulfur Recovery Plant Incinerator SO₂ Concentration

SN #	Source Description	Pollutant	ppm by volume
844	Sulfur Recovery Plant Incinerator	SO ₂ dry basis	250 (Rolling 12-hour)

35. The facility shall use only pipeline quality natural gas as fuel for SN-844. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
36. The SO₂ and O₂ CEMs in use at SN-844 shall be operated in accordance with the Department's CEM Conditions (see Appendix K). The facility shall submit CEM data in accordance with the Department's conditions. CEM data shall be submitted in ppm, lb/hr, and tpy for SN-844.
 [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
37. SN-844 is an affected facility under the provision of 40 CFR 63, Subpart UUU – National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking

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Units, Catalytic Reforming Units, and Sulfur Recovery Units. The UUU requirements are summarize in Plantwide Condition 12. (for the full regulation, see Appendix M)

38. The Sulfur Recovery Unit (SRU) is an affected facility under the provision of 40 CFR 60, Subpart J – Standards of Performance for Petroleum Refineries. The applicable Subpart J requirements are summarized below. (for the full regulation, see Appendix C)
- a. The permittee shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air. The monitor shall be operated as follows:
[§60.105(a)(5)]
 - i. The span values for this monitor are 500 ppm SO₂ and 25 percent O₂.
[§60.105(a)(5)(i)]
 - ii. The performance evaluations for this SO₂ monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. [§60.105(a)(5)(ii)]
 - b. The permittee shall report excess emissions for all 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under §60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air).
[§60.105(e)(4)(i)]
 - c. For any periods for which sulfur dioxide or oxides emissions data are not available, the permittee shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability. [§60.107(d)]
 - d. The permittee shall submit a report on the SO₂ CEM system which contains all of the information required by §60.107(d). This report shall be submitted to the Department in accordance with the Department CEM Conditions (Appendix K). [§60.107(e)]
 - e. The owner or operator of the facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. [§60.107(f)]

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SN-821a, 821b, 821c - Refinery Boilers (Three Boilers)

Source Description

This source consists of the three new refinery boilers to be installed at the facility as part of the boiler replacement project required by the Consent Decree (CIV. No. 03-1028) reached between Lion Oil, ADEQ, and the US EPA. The total rated heat input capacity for all three boilers will be 605 MMBtu/hr on an annual average basis. Individually the boilers each operate at a maximum of 221.8 MMBtu/hr for a total maximum heat input capacity of 665.5 MM Btu/hr. These boilers are being permitted to burn NSPS Subpart J quality gas, or #2 fuel oil. Each of the boilers will utilize next-generation ultra-low-NO_x burners for NO_x emission control.

Regulations

All three of the refinery boilers are subject to each of the following regulations: 40 CFR Part 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR Part 60 Subpart J – Standards of Performance for Petroleum Refineries.

The emission limitations established for this source were relied upon in a PSD netting analysis. Future increases in these permitted levels may trigger PSD review for these sources.

Specific Conditions

39. The listed sources shall not exceed the emission rates set forth in the following table. The limits given in this table represent the combined emissions from all three boiler exhaust stacks. Compliance with these limits shall be demonstrated by compliance with Specific Conditions #40, #43, #45, #47, #49, #52, #53 or with other available emissions data for these sources. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 22 - Refinery Boilers Criteria Emissions

SN	Source Description	Pollutant	lb/hr	tpy	lb/MMBtu
821	Three Boilers - burning NSPS Subpart J quality gas	PM ₁₀	7.8	---	0.0117
		SO ₂	22.4	---	0.0336
		VOC	9.8	---	0.0147
		CO	474.2	---	0.7126
		NO _x	23.3	---	0.0350
821	Three boilers – burning #2 fuel oil	PM ₁₀	15.7	---	0.0236
		SO ₂	37.3	---	0.0561
		VOC	20.0	---	0.0300
		CO	474.2	---	0.7126
		NO _x	66.6	---	0.1000
821	Refinery Boilers - Annual Emission Limitations (regardless of fuel)	PM ₁₀	---	31.1	---
		SO ₂	---	81.3	---
		VOC	---	39.1	---
		CO	---	123.2	---
		NO _x	---	58.0	---

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40. The facility shall not exceed a total combined annual firing rate of 5,314,320 MMBtu during any consecutive 12-month period at the refinery boilers (SN-821a, 821b, and 821c combined). [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]
41. Total maximum heat input capacity of the boilers (SN-821a, b, and c) shall not exceed 665.5 MMBtu/hr. Compliance shall be verified by totaling nameplate heat input capacity. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]
42. The facility shall analyze the Btu content of all fuels fired in the refinery boilers on a monthly basis. These records shall include the fuel combusted and heat duty (amount of fuel x heating value). The records of Btu content shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
43. The facility shall not exceed 5% opacity from the sources in this section. Compliance with this limit shall be demonstrated by burning pipeline quality natural gas or refinery fuel gas with an H₂S concentration less than 1,500 ppmvd. If the H₂S concentration exceeds 1500 ppmvd, then the facility shall comply with Specific Condition #44 . [§18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
44. During those times in which the H₂S content of the refinery fuel gas combusted on-site exceeds 1500 ppmvd, the facility shall conduct an opacity observation for those sources which are permitted to combust NSPS Subpart J quality gas. These observations shall be conducted by someone who is familiar with the visible emissions from these sources. Any sources which generate visible emissions during these periods shall be considered to be in violation of the 5% opacity standard for that source. Records of these observations shall be maintained on-site, and shall be made available to the Department upon request. These records shall indicate the date and time of the observation, the name of the person making the observation, whether or not any visible emissions are detected, and a list of any sources (by SN) for which visible emissions were noted. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
45. The facility shall not exceed 20% opacity from the refinery boilers (SN-821a, b, or c) when burning fuel oil. Compliance with this condition shall be demonstrated by compliance with Specific Condition #46. [§19.503 of Regulation 19 and 40 CFR Part 52 Subpart E]
46. During periods of pipeline quality natural gas curtailment when fuel oil is burned as a fuel in the refinery boilers (SN-821), the facility shall conduct an opacity observation. These observations shall be conducted by someone who is familiar with the visible emissions from these sources. Records of these observations shall be maintained onsite and made available to Department personnel upon request. The requirement to conduct an opacity observation does not apply during testing and preventative maintenance of the fuel oil delivery system. [§19.503 of Regulation 19 and 40 CFR Part 52 Subpart E]
47. The facility shall use only pipeline quality natural gas or NSPS Subpart J quality gas as fuel for the refinery boilers (SN-821). In the event of pipeline quality natural gas curtailment, emergency, or upset conditions as set forth in Chapter 6 of Regulation 19, the boilers may be fired with fuel oil if fuel gas is unavailable. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]

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48. In the event that fuel oil is used at this source, the facility shall maintain records of fuel oil usage including the amount of fuel oil used and the sulfur content of the fuel oil. Records shall be maintained on site and submitted in accordance with Chapter 6 of Regulation 19. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
49. The permittee shall not exceed an NO_x emission rate of 0.035 lb/MMBtu based on a rolling 3-hour average from any of the three refinery boilers (SN-821a, 821b and 821c). [§19.501 et seq. of Regulation 19, 40 CFR Part 52 Subpart E]
50. The permittee shall not exceed a rolling 12-month average CO emission rate of 0.0570 lb/MMBtu or 123.2 tpy as calculated from the CEM systems. [§19.405(B) and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
51. The permittee shall install, operate, and maintain continuous emission monitoring (CEM) systems on each of the refinery boiler stacks (SN-821a, 821b, 821c) to monitor stack gas concentrations of CO and NO_x. These CEM systems shall comply with the Department's CEM Conditions (Appendix K). [§19.703 of Regulation 19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
52. The refinery boilers (SN-821a, 821b, 821c) are subject to and shall comply with all applicable provisions of 40 C.F.R. 60, Subpart J-Standards of Performance for Petroleum Refineries. They are defined in the subpart as fuel gas combustion devices. The applicable requirements are summarized in Specific Condition #47 and Plantwide Condition #11. (for the full regulation, see Appendix C) [§19.304 of Regulation 19 and 40 CFR §60.100]
53. The refinery boilers (SN-821a, 821b, 821c) are subject to and shall comply with all applicable requirements of 40 CFR Part 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The applicable requirements are summarized below, for the full text of the regulation see 0. [§19.304 of Regulation 19 and 40 CFR §60.40b]
 - a. Affected facilities which also meet the applicability requirements under Subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under subpart J (§60.104). [§60.40b(c)]
 - b. On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. [§60.43b(f)]
 - c. The owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. [§60.48b(a)]

- d. Except as provided under §60.44b(k) and (l), on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts oil or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO₂) in excess of 0.1 lb/MMBtu for distillate oil or gas-fired low heat release rate boilers or 0.2 lb/MMBtu for distillate oil or gas-fired high heat release rate boilers. [§§60.44b(a), (l)(1), and (l)(2)]
- e. The nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction. [§60.44b(h)]
- f. Compliance with the emission limits under this section is determined on a 30-day rolling average basis. Compliance shall be demonstrated by using the data collected to demonstrate compliance with Specific Condition 49. If the data collected to demonstrate compliance with Specific Condition 49 does not meet the requirements of this section, then Lion may be required to produce records to demonstrate compliance on a 30-day rolling average basis. [§60.44b(i)]
- g. Compliance with the NO_x standard under §60.44b shall be determined through performance testing as specified by §60.46b(e). [§60.46b(c)]
- h. To determine compliance with the emission limits for nitrogen oxides required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring nitrogen oxides under §60.48(b). [§60.46b(e)]
- i. The permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere. [§60.48b(b)(1)]
- j. The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments. [§60.48b(c)]
- k. The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(b). At least 2 data points must be used to calculate each 1-hour average. [§60.48b(d)]
- l. The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems. [§60.48b(e)]

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- m. The span value for NO_x must be determined according to §60.48b(e)(2). All span values are rounded to the nearest 500 ppm. Alternatively ADEQ has approved a span value of 100 ppm for the boiler NO_x CEMS. [§60.48b(e)(2 and (3))]
- n. When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days. [§60.48b(f)]
- o. The permittee shall submit notification of the date of initial startup, as provided by §60.7. The notification shall include:
 - i. The design heat input capacity of the affected facility and identification of the fuels to be combusted in the facility, and [§60.49b(a)(1)]
 - ii. The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired. [§60.49b(a)(2)]
- p. The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B. [§60.49b(b)]
- q. The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [§60.49b(d)]
- r. The owner or operator of an affected facility subject to the nitrogen oxides standards under §60.44b shall maintain records of the following information and submit the following in required semi-annual reports for each steam generating unit operating day: [§60.49b(g) and (i)]
 - i. Calendar date
 - ii. The average hourly nitrogen oxides emission rates (expressed as NO₂) (ng/J or lb/million Btu heat input) measured or predicted.
 - iii. The 30-day average nitrogen oxides emission rates (ng/J or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days. Compliance with the 0.1 lb/MMBtu NO_x

emission limit shall be demonstrated by using the data collected to verify compliance with Specific Condition 49. If the data collected to demonstrate compliance with Specific Condition 49 does not meet the 0.1 lb/MMBtu NO_x limit, then Lion may be required to produce records to demonstrate compliance with the NSPS 30-day average requirement for NO_x.

- iv. If compliance with Specific Condition 49 is not met, then Lion may be required to produce records to demonstrate compliance with the NSPS 30-day average requirement for NO_x.
- v. Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.
- vi. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.
- vii. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.
- viii. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
- ix. Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
- x. Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.
- xi. Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.
- s. The permittee shall submit excess emission reports for any excess emissions that occurred during the reporting period. For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under §60.46b(e), which exceeds the applicable emission limit in §60.44b. [§60.49b(h)]
- t. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record. [§60.49b(o)]
- u. The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. The 6 month period may coincide with Lion's current semi-annual monitoring reporting (January 1st – June 30th and July 1st – December 31st). [§60.49b(w)]

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SN-822 - High Pressure Flare
SN-823 - Low Pressure Flares

Source Description

SN-822 and SN-823 are steam assisted flares used to provide for the safe disposal of hydrocarbon-vapors discharged from refinery process units from upset conditions, startups, shutdowns and malfunctions. The gases that will be routinely combusted in the flares are pilot gas, purge gas, and NSPS Subpart J quality gas from the fuel gas system.

SN-822 maintains a pilot light designed at 1.5 MM Btu/hr and is known as the high pressure flare. It was installed in 1979.

SN-823 maintains a pilot light designed at 1.5 MM Btu/hr and is known as the low pressure flare. It was installed in 1974.

A Flare Gas Recovery System (FGRS) has been installed at the facility. The purpose of the FGRS is to recover refinery gases. The FGRS compresses the flare gases and allows them to be processed either in the fuel gas system or through the gas plant. When the fuel gas produced exceeds refinery demand, excess gas meeting the requirements of 40 C.F.R., Part 60, Subpart J, may be routed to the flares. The FGRS is not a source of emissions.

Regulations

The flares are both subject to 40 C.F.R., Part 60, Subpart J-*Standards of Performance for Petroleum Refineries*.

Specific Conditions

54. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by operation of the flare gas recovery system and by compliance with the fuel and flow rate limits of this section. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 23 – Flare Criteria Pollutant Emissions

SN #	Source Description	Pollutant	lb/day	tpy
822, 823	Both Flares	PM ₁₀	99	4.0
		SO ₂	484	19.6
		VOC	842	34.1
		CO	2,220	89.9
		NO _x	612	24.8

55. The flare gas recovery system shall be in operation at all times. If the flare gas recovery system is not in operation, Lion Oil is in compliance with this condition provided that the flare is operated and the emission limits in Specific Condition 54 are not exceeded. [§19.705 of Regulation 19, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

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56. The flares shall be operated as required in § 60.18. These requirements are summarized below.
[§19.304 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. § 60.18]
 - a. The flares shall be operated with a flame present at all times as required by § 60.18(c)(2).
 - b. The facility shall monitor the flares to ensure they are operated and maintained in conformance with their designs in accordance with § 60.18(d).
 - c. The flares shall be operated at all times when emissions may be vented to them as required by § 60.18(e).
57. The flares shall be operated with no visible emissions, except for periods not to exceed a total of five minutes during any consecutive two hour period, when the flares may have emissions not to exceed 60% opacity. [§19.304 and §19.503 of Regulation 19 and 40 C.F.R. § 60.18(c)(1)]
58. The high and low pressure flares (SN-822 and SN-823) are affected facilities under the terms of 40 CFR Part 60 Subpart J – Standards of Performance for Petroleum Refineries. These sources are subject to the Subpart J requirements, which are summarized in Plantwide Condition 11. (for the full regulation, see Appendix C). Pipeline quality natural gas meets the requirements of Subpart J. [§19.304 of Regulation 19 and 40 CFR §60.100]
59. The total flow of pilot gas, purge gas and excess NSPS J quality gas to the flares shall be limited to 6 MM scf/day and a total limit of 486 MM scf per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
60. Records for the rolling annual flow rate in Specific Condition #59 shall be maintained on a twelve-month rolling basis, updated monthly. Records shall be maintained to demonstrate compliance with the daily limit in Specific Condition #59. Such records shall be maintained on-site and the 12-month rolling totals shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
61. The flares and flare gas recovery system shall be operated as described in this section at all times. In the event of an upset, emergency condition, startup, shutdown, or malfunction, the Department will forego enforcement action if the permittee complies with the requirements of Regulation 19, Chapter 6, Upset and Emergency Conditions and 40 C.F.R. § 60.11 for federally regulated air pollutant emissions and Regulation 18, Chapter 11, § 18.1101, Upsets, for other air emissions. Permittee shall submit the reports as referenced in §§19.601(C) and 18.1101(B) within 30 days of the upset, emergency condition, startup, shutdown and malfunction.
[§19.601 and §19.602 of Regulation 19, and 40 C.F.R., Part 52, Subpart E, and 40 C.F.R., Part 60]

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SN-824 - Fume Incinerator

Source Description

SN-824 is a 15 MMBtu/hr incinerator (nominal design) used to incinerate hydrocarbon vapors emitted from the asphalt blowing process subsequent to vapor scrubbing. It is fueled by NSPS Subpart J quality gas. It was installed in 1977.

On May 23 – 24, 2001, this source was tested for SO₂ emissions using EPA Reference Method 6C pursuant to §19.702 of Regulation 19, and 40 C.F.R., Part 52, Subpart E.

Regulations

Pursuant to 40 C.F.R. 60, Subpart J-Standards of Performance for Petroleum Refineries, the Asphalt Blowing Incinerator is an affected facility. The provisions of 40 C.F.R. 60, Subpart J do not apply to emissions from asphalt processing facilities.

Pursuant to 40 CFR Part 63 Subpart LLLLL – National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing, the Asphalt Blowing Incinerator is an affected facility.

Specific Conditions

62. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the operational limits for this source. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 24 - Fume Incinerator Criteria Emission Rate

SN #	Source Description	Pollutant	lb/hr	tpy
824	Fume Incinerator	PM ₁₀	2.0	8.8
		SO ₂	23.1	101.5
		VOC	4.1	18.0
		CO	123.3	541.5
		NO _x	2.0	8.8

63. The facility shall use only pipeline quality natural gas or NSPS Subpart J quality gas as fuel to aid in combustion of emissions from the blowing stills. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
64. The facility shall not exceed 5% opacity from the sources in this section. Compliance with this limit shall be demonstrated by burning pipeline quality natural gas or refinery fuel gas with an H₂S concentration less than 1,500 ppmvd. If the H₂S concentration exceeds 1500 ppmvd, then the facility shall comply with Specific Condition #65. [§18.501 of Regulation 18, and A.C.A. §84-203 as referenced by §8-4-304 and §8-4-311]
65. During those times in which the H₂S content of the refinery fuel gas combusted on-site exceeds 1500 ppmvd, the facility shall conduct an opacity observation for those sources which are

permitted to combust NSPS Subpart J quality gas. These observations shall be conducted by someone who is familiar with the visible emissions from these sources. Any sources which generate visible emissions during these periods shall be considered to be in violation of the 5% opacity standard for that source. Records of these observations shall be maintained on-site, and shall be made available to the Department upon request. These records shall indicate the date and time of the observation, the name of the person making the observation, whether or not any visible emissions are detected, and a list of any sources (by SN) for which visible emissions were noted. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

66. The Fume Incinerator (SN-824) is subject to and shall comply with all applicable provisions of 40 CFR Part 63 Subpart LLLLL – National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing. The compliance requirements of this subpart as they apply to these sources are summarized below. [§19.304 of Regulation 19 and 40 CFR §63.8681]

- a. SN-824 shall maintain the 3-hour combustion zone temperature at or above the operating limit established during performance testing (1523°F). [§63.8684(b)]
- b. SN-824 shall comply with the emission limitations (including operating limits) in this subpart at all times, except during periods of startup, shutdown, and malfunction. [§63.8685(a)]
- c. The permittee must always operate and maintain the affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i). [§63.8685(b)]
- d. The permittee shall develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3). [§63.8685(c)]
- e. The permittee shall develop and implement a written site-specific monitoring plan according to the provisions in §63.8688(g) and (h). [§63.8685(d)]
- f. The permittee shall conduct performance tests no later than 180 days after the compliance date that is specified for your source in §63.8683 and according to the provisions in §63.7(a)(2). As an alternative, the permittee may use the results of a previously-conducted emission test to demonstrate compliance with the emission limitations in this subpart if you demonstrate to the Administrator's satisfaction that:
 - i. 40cfr63.8686(b)(1)
No changes have been made to the process since the time of the emission test; and
 - ii. 40cfr63.8686(b)(2)
The operating conditions and test methods used during testing conform to the requirements of this subpart; and

- iii. The control device and process parameter values established during the previously-conducted emission test are used to demonstrate continuous compliance with this subpart.
- g. The permittee shall conduct each performance test in accordance with Table 3 of Subpart LLLLL. Each performance test must be conducted as follows: [§63.8687(a) through (e)]
 - i. Each performance test must be conducted under normal operating conditions and under the conditions specified in Table 3 to Subpart LLLLL.
 - ii. Performance testing shall not be conducted during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).
 - iii. Except for opacity and visible emission observations, three separate test runs shall be conducted for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.
 - iv. The permittee must use the equations of §63.8687(e) to determine compliance with the emission limitations.
- h. The permittee shall install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the requirements of §63.8688(a) and (b).
- i. For each monitoring system required in this section, the permittee must develop and make available for inspection by the permitting authority, upon request, a site-specific monitoring plan. The site-specific monitoring plan must address the following: [§63.8688(g) and (h)]
 - i. Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (c)(3), (c)(4)(ii), (c)(7), and (c)(8);
 - ii. Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and
 - iii. Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).
- j. The permittee must conduct a performance evaluation of each CPMS, CEMS, or COMS in accordance with your site-specific monitoring plan. [§63.8688(i)]
- k. The permittee must operate and maintain the CPMS, CEMS, or COMS in continuous operation according to the site-specific monitoring plan. [§63.8688(j)]
- l. The permittee shall submit all of the notifications in §§63.6(h)(4) and (5), 63.7(b) and (c), 63.8(f), and 63.9(b) through (f) and (h) that apply to you by the dates specified. [§63.8692(a)]
- m. As specified in §63.9(b)(2), the permittee must submit an Initial Notification not later than 120 calendar days after April 29, 2003. [§63.8692(b)]

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- n. The permittee shall submit a notification of intent to conduct performance testing at least fifteen (15) days prior to the date the testing is scheduled to begin.
- o. The permittee shall submit a notification of compliance status according to §63.9(h)(2)(ii). This notification shall include all performance test results, and shall be submitted by the close of business on the 60th calendar day following the completion of the performance tests according to §63.10(d)(2). If you are using data from a previously-conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must submit the test data in lieu of the initial performance test results with the Notification of Compliance Status. [§63.8692(e) and (f)]

SN-831 -#9 Continuous Catalyst Regenerator (CCR)

Source Description

SN-831 is a regenerator used to continuously burn off the coke deposit from the catalyst, and restore catalyst activity, selectivity, and stability. This source was installed in 1991. Usage of a new catalyst was implemented in 2003/2004 in order to produce additional hydrogen for the No. 8 and No. 10 hydrotreating processes.

Specific Conditions

67. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limit for this source. [§19.501 of Regulation 19 et seq., and 40 C.F.R., Part 52, Subpart E]
68. Temp reserve
69. Temp reserve
70. Temp reserve
71. Temp reserve

Table 25 - #9 Continuous Catalyst Regenerator Criteria Pollutant Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
831	#9 Continuous Catalyst Regenerator	PM ₁₀	2.0	8.8
		SO ₂	2.0	8.8
		VOC	2.0	8.8
		CO	2.6	11.4
		NO _x	2.0	8.8

72. The total amount of catalyst recirculated at this source shall be limited to 13.2 million pounds per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
73. Records for the recirculation rate shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
74. SN-831 (the CCR) is an affected facility under the terms of 40 C.F.R., Part 63, Subpart UUU- National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. The applicable requirements of this subpart are summarized in Plantwide Condition 12. [§19.304 of Regulation 19 and 40 CFR §63.1561]

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SN-832 - 47 Asphalt Tank Heaters

Source Description

SN-832 is comprised of 47 tank heaters with a total heat input capacity of 99.3 MMBtu/hr (nominal design). The heaters are used to maintain elevated temperatures of stored asphalt products so that the material will flow and not solidify. The heaters included in this source grouping are described in the following table.

Table 26 - Asphalt Tank Heaters

Tank SN	Year Installed	# of Heaters	MMBtu/hr per heater	total MMBtu/hr per tank
T-39	pre-1981	2	3.0	6.0
T-40	1988	1	2.3	2.3
T-41	1991	1	2.3	2.3
T-56	1989	2	1.5	3.0
T-78	1999	3	0.68	2.1
T-99	1991	2	0.15	0.3
T-107	1987	4	2.75	11.0
T-111	pre-1981	4	1.8	7.2
T-118	1987	4	2.75	11.0
T-219	1968	4	1.8	7.2
T-348	1968	2	2.3	4.6
T-354	2001	2	1.5	3.0
T-524	1986	4	2.3	9.2
T-530	1986	4	2.3	9.2
T-544	1991	2	0.5	1.0
T-548	1993	6	3.33	20

Because the combined emissions from these sources emit more than 10 tpy of a single criteria pollutant, they cannot be classified as insignificant emission sources. These sources have been permitted at full capacity and fire only NSPS Subpart J quality gas.

Regulations

These sources are subject to 40 C.F.R., Subpart J- *Standards of Performance for Petroleum Refineries* as fuel gas combustion devices.

Specific Conditions

75. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by permitting these sources at full capacity and compliance with NSPS Subpart J. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 27 - Asphalt Tank Heaters Criteria Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
832	47 Asphalt Tank Heaters	PM ₁₀	1.0	4.4
		SO ₂	4.3	14.7
		VOC	1.0	4.4
		CO	10.6	35.9
		NO _x	12.9	43.6

76. The facility shall not exceed 5% opacity from the sources in this section. Compliance with this limit shall be demonstrated by burning pipeline quality natural gas or refinery fuel gas with an H₂S concentration less than 1,500 ppmvd. If the H₂S concentration exceeds 1500 ppmvd, then the facility shall comply with Specific Condition #77. [§18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
77. During those times in which the H₂S content of the refinery fuel gas combusted on-site exceeds 1500 ppmvd, the facility shall conduct an opacity observation for those sources which are permitted to combust NSPS Subpart J quality gas. These observations shall be conducted by someone who is familiar with the visible emissions from these sources. Any sources which generate visible emissions during these periods shall be considered to be in violation of the 5% opacity standard for that source. Records of these observations shall be maintained on-site, and shall be made available to the Department upon request. These records shall indicate the date and time of the observation, the name of the person making the observation, whether or not any visible emissions are detected, and a list of any sources (by SN) for which visible emissions were noted. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
78. The facility shall burn only pipeline quality natural gas or NSPS Subpart J quality gas at the sources included in SN-832. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
79. The Asphalt Heaters (SN-832) is an affected facility under the provisions of 40 C.F.R. 60, Subpart J-Standards of Performance for Petroleum Refineries. It is defined in the subpart as a fuel gas combustion device. They are defined in the subpart as fuel gas combustion devices subject to the Subpart J requirements summarized in Plantwide Condition 11 (for the full regulation, see Appendix C). [§19.304 of Regulation 19 and 40 CFR §60.100]

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SN-834 - North KVG Compressor
SN-835 - South KVG Compressor
SN-836 - 8GTL Compressor
SN-837 - North 8 SVG 440 hp Compressor
SN-838 - South 10 SVG 550 hp Compressor
SN-839 - East JVG Compressor
SN-840 - West JVG Compressor
SN-841 - G398TA Air Compressor

Source Description

All of the following described sources are pipeline quality natural gas compressor engines used to move gases within refinery plant operations. They are all fueled by pipeline quality natural gas.

The Consent Decree (CIV. No. 03-1028) reached between Lion Oil, the US EPA, and ADEQ required that Lion install and operate controls on SN-837, SN-838, SN-839, and SN-840 as an "environmentally beneficial project". Additionally, a BACT analysis was performed for CO emissions from the Air Compressor (SN-841), and BACT was proposed to be the installation of non-selective catalytic reduction (NSCR) with air/fuel ratio controls. EPA has not yet granted final approval of the proposed BACT for SN-841, and the unit will operate under an interim CO emission limit of 2.0 g/hp-hr until such time as a final BACT limit is established. The installation of these control devices will result in decreases in both actual and permitted emissions of CO and NO_x from these engines.

SN-834 through SN-840 has been converted to electrical power and are no longer emission sources. SN-841 will continue to operate until 30 days after SN-841A begins operation, after which, the source will be removed from service.

Table 28 - Compressors

Compressor SN	Year Installed	rated power (hp)
833*	1959	--
834*	1942	650
835*	1942	650
836*	1986	959
837*	1958	440
838*	1958	550
839*	1959	240
840*	1959	240
841A	2007	815
841	1959	700
* Sources removed from Service.		

Specific Conditions

80. The permittee shall not exceed the emission rates set forth in the following tables. The permittee shall comply with the emission limits contained in the table below. Compliance with these limits shall be demonstrated by compliance with the operation and testing limits of this section. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 29 – Compressors Criteria Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
833	South XVG Compressor	Removed from service		
834	North KVG Compressor	Removed from service		
835	South KVG Compressor	Removed from service		
836	8GTL Compressor	Removed from service		
837	North 8SVG Compressor w/Catalytic Converter	Converted to Electric Power		
838	South 10 SVG Compressor w/Catalytic Converter	Converted to Electric Power		
839	East JVG Compressor	Replaced with Electric Driven Compressor		
840	West JVG Compressor	Replaced with Electric Driven Compressor		
841	G398TA Air Compressor	CO	3.1	13.6
		NO _x	3.1	13.6
841A	G3512TA Air Compressor	CO	7.0	23.7
		NO _x	4.7	15.8

Negligible amounts of particulate matter and sulfur dioxide may be emitted by these sources. Due to extremely low potential emissions of these pollutants, numerical limits have not been included for these sources, but such emissions are not prohibited.

81. The facility shall not exceed 5% opacity from SN's 841 and 841A. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas. [§18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
82. Temp reserve
83. Temp reserve
84. The facility shall use only pipeline quality natural gas as fuel for the compressors within this section. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
85. Within 180 days after the installation of SN-841A and every five years thereafter, the permittee shall simultaneously conduct tests for CO and NO_x SN-841A in accordance with Plantwide

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Condition #3. EPA Reference Method 7E (or other approved method) shall be used to test NO_x for the reciprocating engines and EPA reference Method 10 (or other approved method) shall be used to determine CO. EPA Reference Method 19 shall be used to convert test results to mass emission rates. The results of this testing shall be maintained on-site, and shall be submitted to the Department in accordance with General Provision #7. [§19.702 of Regulation 19 and 40 CFR Part 52 Subpart E]

86. Temp reserve
87. Temp reserve
88. The permittee shall install, operate, and properly maintain a catalytic converter with air-to-fuel ratio controls on the Air Compressor (SN-841) for the purpose of reducing CO emissions to the atmosphere. These controls shall be installed and operational no later than December 31, 2004. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
89. On and after December 31, 2004, until such time as a final BACT limit for CO is established by the US EPA, the permittee shall operate the Air Compressor (SN-841) such that CO emissions to the atmosphere do not exceed 2.0 g/hp-hr based on a 3-hour average. Once a final BACT limit is established by the US EPA, then the permittee shall comply with that limit. [§19.501 et seq. and 40 CFR Part 52 Subpart E]
90. Within 60 days after the installation of SN-841, the permittee shall test the compressor exhaust stack for emissions of CO and NO_x. CO testing shall be performed in accordance with US EPA Reference Method 10, and NO_x testing shall be performed in accordance with US EPA Reference Method 7E. EPA Reference Method 19 shall be used to convert test results to mass emission rates. The results of this testing shall be maintained on-site, and shall be submitted to the Department in accordance with General Provision #7. [§19.702 of Regulation 19 and 40 CFR Part 52 Subpart E]
91. The permittee shall continue to test the CO emissions from the Air Compressor (SN-841) according to the following schedule. All CO testing shall be performed in accordance with US EPA Reference Method 10. EPA Reference Method 19 shall be used to convert test results to mass emission rates. All test results shall be maintained on-site, and shall be submitted to the Department in accordance with General Provision #7. [§19.702 of Regulation 19 and 40 CFR Part 52 Subpart E]
 - a. A test shall be performed within 30 days prior to the beginning of the first scheduled semi-annual maintenance of the compressor (SN-841). During the maintenance downtime, the catalytic converter shall be serviced in accordance with the manufacturer's directives.
 - b. An additional test shall be performed within 30 days following the end of the first scheduled semi-annual maintenance of the compressor (SN-841).
 - c. The testing procedures outlined in (a) and (b) above shall be repeated for the second scheduled semi-annual maintenance of the air compressor (SN-841). During the

maintenance downtime, the catalytic converter shall be serviced in accordance with the manufacturer's directives.

- d. The testing shall be repeated again within 30 days prior to the beginning of the fourth scheduled semi-annual maintenance of the air compressor (after the catalytic converter is installed).
 - e. All of the above testing shall be completed no later than 30 months after the date that the air compressor is installed and first operated.
 - f. The air compressor (SN-841) shall continue to be tested for CO on an annual basis from the date that the test required in section (d) above is completed.
92. Each catalytic converter system operated on a stationary engine at the Lion Oil facility shall be operated and maintained in accordance with the manufacturer's specifications and directives at all times. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
93. The G3512TA Air Compressor (SN-841A) is subject to and shall comply with all applicable provisions of 40 CFR 63, Subpart ZZZZ. SN-841A is a new four-stroke rich burn (4SRB) compressor. The compliance requirements of this subpart as they apply to this source are summarized below. [§19.304 of Regulation 19 and 40 CFR 63.6585]
- a. The permittee shall comply with the applicable emission limitations in Table 1a of Subpart ZZZZ and the operating limits in Table 1b of Subpart ZZZZ upon startup of the affected source. [40 CFR §63.6600(a)]
 - i. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15% oxygen. [40 CFR 63, Table 1a]
 - ii. Maintain the catalyst so that the pressure drop across the catalyst does not change by more than two inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test. [40 CFR 63, Table 1b]
 - iii. Maintain the temperature of the RICE exhaust so that the catalyst inlet temperature is between 750 °F to 1250°F. [40 CFR 63, Table 1b]
 - iv. Comply with an operating limitations approved by the Administrator. [40 CFR 63, Table 1b]
 - b. The permittee shall comply with the applicable emission limitations and operating limitations in Subpart ZZZZ at all times, except during periods of startup, shutdown, and malfunction. [40 CFR §63.6605(a)]
 - c. The permittee shall operate and maintain the stationary RICE, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control

practices for minimizing emissions at all times, including during startup, shutdown, and malfunction. [40 CFR §63.6605(b)]

- d. Initial compliance shall be demonstrated via the initial performance test or other initial compliance demonstrations in Table 4 of Subpart ZZZZ, no later than 180 days after startup of the source according to the provisions of §63.7(a)(2) and Table 5 of Subpart ZZZZ. [40 CFR §63.6610(a) and §63.6630(a)]
 - i. During the initial performance test, the permittee shall establish each applicable operating limitation in Table 1b of Subpart ZZZZ. [40 CFR §63.30(b)]
 - ii. Complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust, the permittee must: [40 CFR 63, Table 4]
 - 1. Select the sampling port location and the number of traverse points using Method 1 or 1A of 40 CFR part 60, Appendix A §63.7(d)(1)(i). If using a control device, the sampling site must be located at the outlet of the control device.
 - 2. Determine the O₂ concentration of the stationary RICE exhaust at the sampling port location using Method 3 or 3A or 3B of 40 CFR part 60, Appendix A. Measurements to determine O₂ concentration must be made at the same time and location as the measurements for formaldehyde concentration.
 - 3. Measure moisture content of the stationary RICE exhaust at the sampling port location using Method 4 of 40 CFR part 60, Appendix A, or Test Method 320 of 40 CFR part 63, Appendix A, or ASTM D 6348-03.
 - 4. Measure formaldehyde at the exhaust of the stationary RICE using Method 320 or 323 of 40 CFR 63, Appendix A; or ASTM D6348-03. Formaldehyde concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
 - iii. Complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust, the permittee has demonstrated initial compliance if : [40 CFR 63, Table 5]
 - 1. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation.
 - 2. The permittee has installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), and
 - 3. The permittee has recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.

- e. The permittee shall conduct subsequent performance tests as specified in Table 3 of Subpart ZZZZ. [40 CFR §63.6615]
 - i. Subsequent performance tests must be conducted semiannually. [40 CFR 63, Table 5]
 - ii. After the permittee has demonstrated compliance for two consecutive tests, then the permittee may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent performance test indicate the stationary RICE is not in compliance with the formaldehyde emission limitation, or the permittee has deviated from any operating limitations, the permittee must resume semiannual performance tests. [40 CFR 63, Table 5]
- f. The permittee shall install, operate, and maintain each CMPS to continuously monitor catalyst inlet temperature, required in Table 6 to Subpart ZZZZ according to the requirements in §63.8. [40 CFR §63.6625(b)]
- g. The permittee shall monitor continuously at all times that the stationary RICE is operating except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks, and required zero and span adjustments). The permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The permittee must, however, use all the valid data collected during all other periods. [40 CFR §63.6635(b) and (c)]
- h. The permittee shall demonstrate continuous compliance with each applicable emission limitation and operating limitation in Table 1a and 1b and of Subpart ZZZZ according to methods specified in Table 6 of Subpart ZZZZ. [40 CFR §63.6640(a)]
 - i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit; [40 CFR 63, Table 6]
 - ii. Collecting the catalyst inlet temperature data according to §63.6625(b); [40 CFR 63, Table 6]
 - iii. Reducing these data to 4-hour rolling averages; [40 CFR 63, Table 6]
 - iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; [40 CFR 63, Table 6]
 - v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. [40 CFR 63, Table 6]
- i. The permittee shall report each instance in which the permittee did not meet an applicable emission limitation or operating limitation in Tables 1a and 1b of Subpart ZZZZ. These

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instances are deviations from the emission and operating limitations in Subpart ZZZZ. These deviations must be reported according to the requirements in 63.6650. If the permittee changes catalyst, the permittee must reestablish the values of the operating parameters measured during the initial performance test. When the permittee reestablishes the values of their operating parameters, the permittee must also conduct a performance test to demonstrate that the permittee is meeting the required emission limitation applicable to their stationary RICE. [40 CFR §63.6640(b)]

- j. Consistent with 63.6(e) and 63.7(e)(1), deviations from the emission or operating limitations that occur during a period of startup, shutdown, or malfunction are not violations if the permittee demonstrates to the Administrator's satisfaction that the source was operating in accordance with 63.6(e)(1). As a new source, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. [40 CFR §63.6640(d)]
- k. The permittee shall report each instance in which the source did not meet the requirements in Table 8 of Subpart ZZZZ that apply. [40 CFR §63.6640(e)]
- l. The permittee shall submit all of the applicable notifications in 63.7(b) and (c), 63.8(e), (f)(4), (f)(6), 63.9(b) through (e), and (g), (h), by the dates specified. [40 CFR §63.6645(a)]
- m. The permittee shall submit an Initial Notification not later than 120 days after the source becomes subject to this subpart. [40 CFR §63.6645(c)]
- n. The permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in 63.7(b)(1). [40 CFR §63.6645(e)]
- o. The permittee shall submit a notification of compliance status according to 63.9(h)(2)(ii). This notification shall include all performance test results, and shall be submitted by the close of business on the 60th day following the completion of the performance tests according to 63.10(d)(2). [40 CFR §63.6645(f)]
- p. The permittee shall submit each applicable report in Table 7 of Subpart ZZZZ. [40 CFR §63.6650(a)]
 - i. Each semiannual Compliance Report must contain:
 - 1. If there are no deviations from any emission limitations, operating limitations that apply, or any periods during which the CPMS was out of control as specified by §63.8(c)(7), a statement that there were no deviations or out of control periods during the reporting period.
 - 2. If there were deviations from any emission limitations, operating limitations that apply, or any periods during which the CPMS was out of control as specified by §63.8(c)(7), the permittee must submit the information in §63.6650(d) and §63.6650(e).

3. If the permittee had a startup, shutdown, or malfunction during the reporting period, the information in §63.10(d)(5)(i).
- ii. Each immediate startup, shutdown, and malfunction report if actions addressing the startup, shutdown, or malfunction were inconsistent with the permittee's startup, shutdown, and malfunction plan during the reporting period must contain:
 1. Actions taken for the event;
 2. The information in §63.10(d)(5)(i).
- iii. Each annual report must contain:
 1. The fuel flow rate of each fuel and the heating values that were used in calculations, and
 2. The operating limits provided in the permittee's permit and any deviations from these limits; and
 3. Any problems or errors suspected with the meters.
- q. Unless the Administrator has approved a different schedule for submission of reports under 63.10(a), the permittee shall submit each report by the date in Table 7 of this subpart and according to the following requirements: [40 CFR §63.6650(b)]
 - i. The first Compliance Report must cover the period beginning on the compliance date that is specified for your affected source in 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in 63.6595. [40 CFR §63.6650(b)(1)]
 - ii. The first Compliance Report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in 63.6595. [40 CFR §63.6650(b)(2)]
 - iii. Each subsequent Compliance Report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. [40 CFR §63.6650(b)(3)]
 - iv. Each subsequent Compliance Report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. [40 CFR §63.6650(b)(4)]
 - v. For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent Compliance Reports

according to the dates the permitting authority has established instead of according to the dates in paragraphs 1 through iv. [40 CFR §63.6650(b)(5)]

- r. The Compliance Report must contain the information in 63.6650(c)(1) through 63.650(c)(6). [40 CFR §63.6650(c)]
 - i. Company name and address; [40 CFR §63.6650(c)(1)]
 - ii. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and the completeness of the report; [40 CFR §63.6650(c)(2)]
 - iii. Date of the report and beginning and ending dates of the reporting period; [40 CFR §63.6650(c)(3)]
 - iv. The information in §63.10(d)(5)(i) if there was a startup, shutdown, or malfunction during the reporting period; [40 CFR §63.6650(c)(4)]
 - v. A statement that there were no deviations from the emission or operating limitations during the reporting period, if there were no deviations; [40 CFR §63.6650(c)(5)]
 - vi. A statement that there were no periods which the CPMS was out of control, if there were no out of control instances during the reporting period; [40 CFR §63.6650(c)(6)]
- s. For each deviation from an emission or operating limitations occurring for a stationary RICE where the source is using a CMS to comply with the emission and operating limitation in this subpart, the permittee must include information in §63.6650(c)(1) through §63.650(c)(6) and §63.6650(e)(1) through §63.650(e)(12). [40 CFR §63.650(e)]
 - i. The date and time that each malfunction started and stopped; [40 CFR §63.650(e)(1)]
 - ii. The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high level checks; [40 CFR §63.650(e)(2)]
 - iii. The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8); [40 CFR §63.650(e)(3)]
 - iv. The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period; [40 CFR §63.650(e)(4)]
 - v. A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period; [40 CFR §63.650(e)(5)]

- vi. A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and the other unknown causes; [40 CFR §63.650(e)(6)]
 - vii. A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period; [40 CFR §63.650(e)(7)]
 - viii. An identification of each parameter and pollutant that was monitored at the stationary RICE; [40 CFR §63.650(e)(8)]
 - ix. A brief description of the stationary RICE; [40 CFR §63.650(e)(9)]
 - x. A brief description of the CMS; [40 CFR §63.650(e)(10)]
 - xi. The date of the latest CMS certification or audit; [40 CFR §63.650(e)(11)]
 - xii. A description of any changes in CMS, processes, or controls since the last reporting period. [40 CFR §63.650(e)(12)]
- t. Each affected source that obtained a Title V operating permit pursuant to 40 CFR 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance Report pursuant to Table 7 of Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and from any emission or operating limitation in this subpart, submission of the Compliance Report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance Report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. [40 CFR §63.6650(f)]
- u. The permittee must keep the following records:
- i. A copy of each notification and report that was submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that was submitted according to the requirement in §63.10(b)(2)(xiv). [40 CFR §63.6655(a)(1)]
 - ii. The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction. [40 CFR §63.6655(a)(2)]
 - iii. Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii). [40 CFR §63.6655(a)(3)]
 - iv. Records described in §63.10(b)(2)(vi) through (xi) for each CPMS. [40 CFR §63.6655(b)(1)]

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- v. Previous, i.e. superseded, versions of the performance evaluation plan as required in §63.8(d)(3). [40 CFR §63.6655(b)(2)]
 - vi. Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable. [40 CFR §63.6655(b)(3)]
 - v. The permittee shall keep the records required in Table 6 of Subpart ZZZZ to show continuous compliance with each applicable emission or operating limitation. [40 CFR §63.6655(d)]
 - w. Records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1). [40 CFR §63.6660(a)]
 - x. As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR §63.6660(b)]
 - y. The permittee shall keep each record readily accessible in hard copy or electronic form on-site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off-site for the remaining 3 years. [40 CFR §63.6660(c)]
94. The existing compressor, SN-841, shall cease operation and be rendered inoperable or dismantled within 30 days after the start of normal operations of SN-841(A). [§19.901 of Regulation 19 and 40 CFR 52, Subpart E]

SN-846 - Gasoline/Diesel Loading Rack

Source Description

SN-846 is gasoline and diesel loading rack. It was installed in 1980. A John Zink Carbon Adsorption Vapor Recovery Unit (VRU) was placed into operation on June 18, 1998, in order to comply with the requirements of 40 C.F.R. 63, Subpart CC-National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The requirements of Subpart CC are outlined in the Plantwide Conditions of this permit.

Regulations

This source is not subject to 40 C.F.R. 60, Subpart XX-Standards of Performance for Bulk Gasoline Terminals because it was constructed prior to the effective date of Subpart XX.

Specific Conditions

95. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with 40 C.F.R. 63, Subpart CC and the throughput and loading requirements for this source. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 30 - Gasoline/Diesel Loading Rack VOC Emissions

SN	Pollutant	lb/hr	tpy
846	VOC	20.2	17.1

96. The total annual throughput of gasoline/diesel products through this source is limited to 9,761,905 bbl per consecutive twelve month period. [§19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
97. Records for the annual throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]
98. The facility shall only load gasoline and diesel products at this loading rack. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
99. TOC emissions concentration shall be less than or equal to 1.1 volume percent. [§19.304 of Regulation 19 and 40 CFR §63.427(a) and (b)]
100. The facility shall operate a TOC CEM system on the gasoline/diesel loading rack in order to demonstrate compliance with 40 CFR Part 63 Subpart CC. All CEMs shall be operated in accordance with the Department's CEM Conditions. The facility shall submit CEM data in accordance with the Department's CEMS Conditions. CEM data shall be submitted to demonstrate that the TOC concentration is less than or equal to 1.1 volume percent. [§19.304 of Regulation 19 and 40 CFR §63.427(a) and (b)]

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SN-847 - Heavy Oil Loading Racks

Source Description

SN-847 is the aggregate emissions of twelve asphalt plant loading racks. The loading racks are described in the following table.

Table 31 - Heavy Oil Loading Racks

Year Installed	Product Loaded
1987	111/219 East Asphalt Truck Rack
Pre-1950	111/219 West Asphalt Truck Rack
Pre-1950	South Asphalt Plant Truck Rack
1975	North PMA Truck Rack*
1989	North Asphalt Plant Truck Rack
Pre-1950	Pumphouse Truck Rack
1986	Lube Oil Truck Rack
Pre-1950	E & W Rail Car Rack
1968	56 Rack
Pre-1950	Protective Coatings Dock
Pre-1950	Asphalt Dock
2000	South PMA Truck Rack
*The PMA Truck Rack was previously known as the Emulsion Plant Truck Rack.	

Specific Conditions

101. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the Plantwide Applicability Limit (PAL) for these sources. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 32 - Heavy Oil Loading Racks VOC Emissions

SN	Pollutant	lb/hr	tpy
847	Heavy Oil Loading Racks		
	VOC	647.2	404.4

102. The facility shall load only asphalt, solvents, and lube oil-type products at these loading racks. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]

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103. The facility has elected to demonstrate compliance for the loading racks through a PAL. To demonstrate compliance with the PAL, the facility shall maintain a monthly inventory of the emissions from each loading rack in this section. This inventory shall be calculated by the methods and equations used in AP-42, 5th Edition, Chapter 5.2, "Transportation and Marketing of Petroleum Liquids." Records for the monthly inventory of emissions from each loading rack shall include the source name, products loaded, monthly throughput, and monthly emissions in pounds and tons. The emissions from this inventory shall be summed to determine the total amount of emissions from the combined loading racks. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
104. Records for the annual VOC emission rate shall be maintained on a twelve month rolling basis, updated monthly. The annual VOC emissions records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
105. In order to maintain the emissions from the PMA project below the PSD significance threshold for VOC, the throughput through the two PMA Asphalt Truck Racks shall be limited to an annual throughput of 1.2 MM bbl. [§19.901 of Regulation 19 et seq., and 40 C.F.R., Part 52, Subpart E]
106. Records for the PGPMA throughput shall be maintained on a daily basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-849 - Standby Diesel Crude Pump

Source Description

SN-849 is a Standby Diesel Crude Pump to be used as a backup to the primary charge pump (electrical) in the event of power failure or other related operational emergencies. This unit is rated at 325 hp and is fueled by diesel oil. This unit is fueled by low-sulfur diesel fuel provided from the low-sulfur diesel storage tank. The Standby Diesel Crude Pump was installed in 1997.

Specific Conditions

107. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the operating limits of this section. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 33 - Standby Diesel Crude Pump Criteria Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
849	Standby Diesel Crude Pump	PM ₁₀	1.4	1.4
		SO ₂	1.2	1.2
		VOC	1.6	1.5
		CO	12.2	11.6
		NO _x	20.2	19.1

108. The facility shall not exceed 20% opacity from this source. As this source operates for only a short period of time each year, a regular compliance demonstration is not necessary. [§18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
109. The total hours of operation for this source shall be limited to 1900 hours per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
110. A meter shall be operated to record the hours of operation of SN-849. Records of the hours of operation shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
111. This source shall only be fired on fuel which contains less than 0.5 percent sulfur. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
112. The facility shall keep records demonstrating the sulfur content of the fuel used at the Standby Diesel Crude Pump (SN-849). These records may be in the form of laboratory analyses performed on the fuel stored in the low-sulfur diesel storage tank which supplies fuel to this unit. If any alternative source of fuel is used to fire this unit, the alternative source and the sulfur content of the alternative fuel shall be documented. These records shall be maintained on-site and shall be made available to Department personnel upon request. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-851 - Wastewater Treatment
SN-851a - Wastewater Collection

Source Description

SN-851, the waste water treatment facility, is used to remove pollutants from refinery waste water. It was installed in the 1970's. This unit has a maximum design capacity of 2500 gallons per minute (GPM), which corresponds to an annual capacity of 1,317.6 MM gal. In order to account for any short-term operational variances at this source, a safety factor of 20% has been included in the lb/hr emission limitation (corresponding to a short-term throughput of 3000 GPM).

Lion Oil has begun a complete redesign of the water collection systems at the facility. This redesign, once completed, will completely segregate the process wastewater from the stormwater at the facility. As part of the new wastewater systems, 6 new tanks will be installed at the facility to hold all process wastewater until it can be processed at the wastewater treatment facility. These tanks have been designated T-275, T-276, T-277, T-278, T-279, and T-280. The existing system will continue to be used for the treatment of facility stormwater. Since the process wastewater will be held in a closed system until treatment, this redesign will greatly reduce emissions from the wastewater processes at the facility.

Until the new wastewater collection system is fully operational, the existing system will continue to be operated as indicated in this permit. In order to allow for the operation of the new wastewater collection system once it is constructed, a separate set of specific conditions which are applicable to the new system have been added to this permit. The facility will be required to comply with both sets of specific conditions until such time as the permit is formally amended to modify the requirements for the "old" wastewater collection system.

Specific Conditions

"Old" Wastewater Collection System

113. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section.

Table 34 – Old Wastewater VOC Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
851	Wastewater Treatment	VOC	900.0	3294.0

114. The total throughput of wastewater at this source shall be limited to 1,317.6 MM gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
115. Records of the wastewater throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

“New” Wastewater Collection System

116. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 35 – New Wastewater VOC Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
851a	Wastewater Collection	VOC	26.1	85.9

117. The total throughput of wastewater at this source shall be limited to 1,064.6 MM gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
118. Records of the wastewater throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
119. The “new” process wastewater collection system shall be designed, installed, and operated in compliance with the applicable provisions of 40 CFR Part 60 Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (Appendix J). The record keeping and reporting requirements of this subpart are summarized below. [§19.304 of Regulation 19 and 40 CFR §60.090]
- For each individual drain system or junction box subject to the requirements of §60.692-2, the location, date, and corrective action shall be recorded for each drain when a problem is identified that could result in VOC emissions as determined in the initial and periodic visual or physical inspections.
 - For each junction box subject to the requirements of §60.692-2, the location, date, and corrective action shall be recorded for inspections required by §60.692-2(b) when a problem is identified that could result in VOC emissions.
 - For each sewer line subject to the requirements of §60.692-2 and §60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by §§60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.
 - For oil-water separators subject to §60.692-3 the location, date, and corrective action shall be recorded for inspections required by §60.692-3(a) when a problem is identified that could result in VOC emissions.
 - For closed vent systems subject to §60.692-5 and completely closed drain systems subject to §60.693-1, the location, date, and corrective action shall be recorded for inspections required by §60.692-5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

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- f. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.
- g. If an emission point is not repaired in the specified amount of time, the reason for the delay as specified in §60.692-6 shall be recorded, along with the signature of the owner or operator whose decision it was that repair could not be effected without a refinery or process shutdown, and the date that the repair or corrective action was successfully completed.
- h. A copy of the design specifications for all equipment used to comply with the provisions of Subpart QQQ shall be kept for the life of the source in a readily accessible location. These records shall include the following information:
 - i. Detailed schematics and piping and instrumentation diagrams.
 - ii. The dates and descriptions of any changes in the design specifications.
- i. Additional information shall be maintained for specific equipment as indicated in 40 CFR §60.697 (f)(3)(i)-(x).
- j. If the permittee elects to install a tightly sealed cap or plug over a drain that is out of active service, the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which indicate the location of such drains.
- k. For stormwater sewer systems subject to the exclusion in §60.692-1(d)(1), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.
- l. For ancillary equipment subject to the exclusion in §60.692-1(d)(2), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.
- m. For non-contact cooling water systems subject to the exclusion in §60.692-1(d)(3), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.
- n. The permittee shall submit to the Department within 60 days after initial startup of the "new" wastewater collection system a certification that the equipment necessary to comply with the standards of Subpart QQQ has been installed and that all necessary initial inspections have been conducted in accordance with these standards.
- o. After the initial certification, the permittee shall submit semiannually a certification that all of the required inspections have been carried out in accordance with the standards of Subpart QQQ.

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120. The permittee shall notify the Air Division Permit Section no later than 60 days prior to beginning operation of the "new" wastewater collection system. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
121. The permittee shall submit an annual report to the Department which details the progress of the installation of the "new" wastewater collection system. This report shall indicate the degree of completion of the "new" wastewater collection system, as well as an up-to-date emission estimate for the "old" wastewater collection system based on the current operating conditions at the refinery. The Department shall reserve the right to modify the permitted emission limitations for the "old" wastewater collection system based on the information contained in this report. This report shall be submitted by August 1 of each calendar year. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]
122. Prior to the refinery expansion modifications contained within Air Permit 868-AOP-R5, the permittee must have completed the "new" wastewater collection system due to credit taken for contemporaneous decreases in VOCs. The permittee shall notify the Department in writing within 14 days after the "new" wastewater collection system is operating. [§19.901 of Regulation 19 and 40 CFR Part 52, Subpart E]

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SN-853 - Cooling Towers
SN-853a - #5 Cooling Tower
SN-853-9 - #9 Cooling Tower
SN-859 - #8 Cooling Tower

Source Description

The #3, 5, 6, 7, 9, and 17 Sulfur Plant cooling towers are used to transfer waste heat from the cooling water to the atmosphere. They were installed in the 1970's. The #1 Cooling Tower was removed from service in 2003 and replaced with the new #8 cooling tower, which has been designated as SN-859.

The #5 cooling tower was modified in 2005 to install drift eliminators for PM₁₀ control. SN-853a was added to account for the particulate emissions from the modified #5 tower. Since this PM₁₀ limit was relied upon in the PSD netting analysis for the boiler replacement project, future changes to this limit may trigger PSD review for the boiler project. As a result of the expansion project, the facility is increasing the water throughput at the #5 cooling tower. Since this source is only increasing by 1.6 tpy particulate, netting for the boiler replacement project would still fall under the PSD netting threshold of 15.0 tpy.

Emissions from all seven cooling towers (3, 5, 6, 7, 8, 9, and 17) are bubbled together under SN-853. Cooling Tower #5 retains SN-853a, Cooling Tower #9 retains SN-853-9, and Cooling Tower #8 retains SN-859 for PSD purposes although the emissions from these towers are included in the SN-853 bubble.

BACT Review for No. 9 Cooling Tower

The #9 Cooling Tower will be installed as a result of the refinery expansion. SN-853-9 was added to account for emissions from the source since these emissions were relied upon in the PSD netting analysis. This source underwent a BACT review for particulate. BACT was determined to be the use of drift eliminators.

Specific Conditions

123. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 36 - Cooling Towers Criteria Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
853	Cooling Towers	VOC	20.2	88.6
		PM ₁₀	20.7	83.9
* SN-853 limits include emissions from all six cooling towers (3, 5, 6, 7, 8, 9, and 17)				

124. The total amount of water circulated at the #3, 5, 6, 7, 8, 9, and 17 Sulfur Plant cooling towers shall be limited to 49.92 billion gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]

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125. The total amount of water circulated at the #5 Cooling Tower (SN-853a) shall be limited to 13.2 billion gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
126. The total amount of water circulated at the #8 Cooling Tower (SN-859) shall be limited to 10.5 billion gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
127. The total amount of water circulated at the #9 Cooling Tower (SN-853-9) shall be limited to 10.5 billion gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
128. The permittee is limited to a Total Dissolved Solids concentration, on an annual average, of 3,000 mg/L at the No. 9 Cooling Tower. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]
129. The permittee shall monitor conductivity on a weekly basis and maintain these records on a continuous, rolling 52-week average. For an initial six month period after beginning operation of this source, the permittee shall, concurrently with conductivity measurements, perform TDS analysis using EPA Method 160.1 or ASTN 2540C. These records shall be kept on-site and shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]
130. Records of the water circulated shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E, beginning April 2, 2001]

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SN-854 - Fugitive Equipment Leaks
SN-858f – Tier 2 Fugitives and Tanks VOC Bubble

Source Description

The fugitive emissions not quantified with the other sources are included in this grouping. This bubble also includes emissions listed in the Tier II Fugitive Bubble (SN-858f). All fugitive emissions from the facility (Including Tier II fugitives) continue to be subject to the 676.4 lb/hr emission limit for SN-854.

Regulations

All fugitive equipment leak sources associated with the Tier II project are subject to 40 CFR Part 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC from Petroleum Refineries.

All sources of VOC equipment leaks associated with the Tier II project are subject to 40 CFR Part 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry as referenced by Subpart GGG (see Appendix G).

Specific Conditions

131. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by an annual emissions inventory and the conditions of 40 C.F.R.60, Subparts GGG and VV, as referenced by Subpart GGG and 40 C.F.R. 63, Subpart CC, for those components subject to the requirements of Subparts GGG, VV or CC (respectively). [§19.501 of Regulation 19 et seq., and 40 C.F.R., Part 52, Subpart E]

Table 37 – Fugitive VOC Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
854	Fugitive Equipment Leaks	VOC	679.8 ²	2977.0
858f	Tier II Fugitive Equipment Leaks	VOC	*	41.3
*Short term emissions from Tier II fugitives are subject to the short- term limit for all facility fugitives found under SN-854.				

132. The facility shall conduct an annual emission inventory to demonstrate compliance with the emission limits of Specific Condition #131. This inventory shall be calculated by the methods and equations used in AP-42, Chapter 5.1 (5th Edition or later version) or Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017 (November 1995 or later version), or other ADEQ-approved method. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R.70.6]
133. Records for the emission inventory required in Specific Condition #132 shall be maintained on an annual basis. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), beginning in year 2003, and shall be submitted to the Department at the following address no later than August 1 of each year. [§19.705 of Regulation 19 and 40 C.F.R. Part 52, Subpart E]

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Arkansas Department of Environmental Quality
Air Division
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134. The equipment, including each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service in the #4 Crude Unit, #6 Hydrotreater/Isomerization Unit, #12 Distillate Hydrotreater, #17 Sulfur Recovery Plant, the Polymer Asphalt Letdown Facility, and the equipment associated with the Tier II clean fuels project, are affected facilities under the terms of 40 CFR Part 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries. For the purposes of recordkeeping and reporting only, compressors are also considered affected facilities (see Appendix F). The facility is subject to the Subpart GGG requirements, which are summarized below. [§19.304 of Regulation 19, and 40 CFR §60.590(a)(1) and (3)]
- a. The facility shall comply with the standards for specific equipment found in §§ 60.482-1 to 60.482-10 of 40 C.F.R. 60, Subpart VV. [§60.592(a)]
 - b. An owner or operator may elect to comply with the alternative standards for valves in §§ 60.483-1 and 60.483-2. [§60.592(b)]
 - c. An owner or operator may apply to the Administrator for a permit modification for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.484. [§60.592(c)]
 - d. Each owner or operator subject to the provisions of this subpart shall comply with the testing provisions of § 60.485 except as provided in § 60.593. [§60.592(d)]
 - e. Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping and reporting provisions of §§ 60.486 and 60.487. [§60.592(e)]
 - f. Each owner or operator subject to the provisions of this subpart may comply with the allowable exceptions to the provisions of subpart VV. [§60.593(a)]
135. This facility is subject to 40 CFR Part 60 Subpart VV-*Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry* as referenced by Subpart GGG (see Appendix G). The facility is subject to the requirements of Subpart VV which are summarized below. [§19.304 of Regulation 19, and 40 CFR §§60.590 and 60.592]
- a. The facility shall demonstrate compliance with the requirements of §§60.482-1 to 60.482-10 for all equipment within 180 days of initial startup. [§60.482-1(a)]

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- b. Compliance with §§60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485. [§60.482-1(b)]
- c. The facility may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in § 60.484. (Note: This will require a permit modification.) [§60.482-1(c)(1)]
- d. If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, or 60.482-10, the facility shall comply with the requirements of that determination. (Note: This will require a permit modification.) [§60.482-1(c)(2)]
- e. The compressors in hydrogen service are not subject to this subpart as per the exemption of § 60.593(b)(1). [§60.482-3(a)]
- f. The facility has no pressure relief devices in gas/vapor service and is not subject to this section. [§60.482-4]
- g. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1(c). [§60.482-6(a)(1)]
- h. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. [§60.482-6(a)(2)]
- i. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. [§60.482-6(b)]
- j. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times. [§60.482-6(c)]
- k. The facility shall comply with the requirements for valves in gas/vapor service or in light liquid service. [§60.482-7]
- l. The facility shall comply with the requirements for closed vent systems and control devices. [§60.482-10]
- m. The facility has elected to comply with the alternative work practice specified in paragraphs (b)(3) of this section. [§60.483-2]
- n. The facility has notified the Administrator before implementing these alternative work practices, as specified in §60.487(d). [§60.483-2(2)]

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- o. The facility has initially complied with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7. [§60.483-2(b)(1)]
- p. After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. [§60.483-2(b)(3)]
- q. If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7 but can again elect to use this section. [§60.483-2(b)(4)]
- r. In conducting the performance tests required in §60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). [§60.485(a)]
- s. The facility shall determine compliance with the standards in §§60.482 and 60.483 as follows: [§60.485(b)]
 - i. Method 21 (or other approved method) shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 (or other approved method). The following calibration gases shall be used:
 - 1. Zero air (less than 10 ppm of hydrocarbon in air); and
 - 2. A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.
- t. The facility shall determine compliance with the no detectable emission standards in §§60.482-2(e), and 60.482-3(i) as follows: [§60.485(c)]
 - i. The requirements of paragraph (b) shall apply.
 - ii. Method 21 (or other approved method) shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.
 - iii. Samples used in conjunction with paragraphs (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare. [§60.485(f)]
- u. The facility shall comply with the recordkeeping requirements of this section. [§60.486(a)(1)]
- v. An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one

recordkeeping system if the system identifies each record by each facility.
[§60.486(a)(2)]

- w. When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply: [§60.486(b)]
 - i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
 - ii. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7(c) and no leak has been detected during those 2 months.
 - iii. The identification on equipment except on a valve, may be removed after it has been repaired.
- x. The provisions of §60.7 (b) and (d) do not apply to affected facilities subject to this subpart. [§60.486(k)]
- y. The facility shall submit semiannual reports to the Administrator beginning six months after the initial start up date. [§60.487(a)]
- z. The initial semiannual report to the Administrator shall include the following information: [§60.487(b)]
 - i. Process unit identification.
 - 1. Number of valves subject to the requirements of §60.482-7, excluding those valves designated for no detectable emissions under the provisions of §60.482-7(f).
 - 2. Number of pumps subject to the requirements of §60.482-2, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2(e) and those pumps complying with §60.482-2(f).
 - 3. Number of compressors subject to the requirements of §60.482-3, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3(i) and those compressors complying with §60.482-3(h).
- aa. All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486: [§60.487(c)]
 - i. Process unit identification.
 - ii. For each month during the semiannual reporting period,
 - 1. Number of valves for which leaks were detected as described in §60.482(7)(b) or §60.483-2,

2. Number of valves for which leaks were not repaired as required in §60.482-7(d)(1),
 3. Number of pumps for which leaks were detected as described in §60.482-2(b) and (d)(6)(i),
 4. Number of pumps for which leaks were not repaired as required in §60.482-2(c)(1) and (d)(6)(ii),
 5. Number of compressors for which leaks were detected as described in §60.482-3(f),
 6. Number of compressors for which leaks were not repaired as required in §60.482-3(g)(1), and
 7. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.
 - iv. Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.
- bb. The facility has elected to comply with the provisions of §60.483-2 and has notified the Administrator of the alternative standard selected 90 days before implementing the provision. If the facility decides to comply with the provisions of §60.483-1, the facility shall notify the Administrator 90 days in advance before implementing the provisions. [§60.487(d)]
 - cc. The facility shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that the facility must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests. [§60.487(e)]
136. In order to demonstrate compliance with Subparts GGG and VV the facility shall maintain a log of the following. [§19.304 of Regulation 19, and 40 C.F.R. 60, Subparts GGG and VV]
- a. Compliance with testing provisions as required by §60.592(d).
 - b. Any exemptions for compressors considered to be in hydrogen service.
 - c. Any exemptions for equipment that is in vacuum service as provided by §60.482-1(d).
 - d. Monthly monitoring results of §60.482-2(a)(1).
 - e. Weekly visual inspection checks of liquids dripping of §60.482-2(a)(2).

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- f. Record of instrument reading of §60.482-2(b)(1).
- g. Record of leaks from pump seal in §60.482-2(b)(2).
- h. Attempts to repair leak within 15 days as provided by §60.482-2(c)(1).
- i. Attempts to repair leak within 5 days as provided by §60.482-2(c)(2).
- j. Records of exemption for each pump equipped with a dual mechanical seal system as provided by §60.482-2(d).
- k. Records of exemption for any pump designated for no detectable emission as provided by §60.482-2(e).
- l. Records of exemption for any pump equipped with a closed vent system as provided by §60.482-2(f).
- m. Records that each sampling connection system is equipped with a closed purge system or closed vent system in §60.482-5(a) and (b) or qualifies for the exemptions.
- n. All in-situ sampling systems that are exempt in §60.482-5(c).
- o. Record of monitoring of potential leaks within 5 days as required by §60.482-8(a).
- p. Record of leaks detected in §60.482-8(b).
- q. Attempts to repair leak within 15 days as provided by §60.482-8(c)(1).
- r. Attempts to repair leak within 5 days as provided by §60.482-8(c)(2).
- s. Record of delay of repair of equipment as allowed in §60.482-9(a) or (b).
- t. Record of delay of repair of equipment as allowed in §60.482-9(c).
- u. Record of delay of repair of equipment as allowed in §60.482-9(d).
- v. Delays of repair beyond a process unit shutdown as allowed in §60.482-9(e).
- w. Record of the percent of valves leaking as required in §60.483-2(5) and (6).
- x. Records of the tests and results of §60.485(d).
- y. Results of §60.485.
- z. Records of §60.485(g).
- aa. Information required by §60.486(c) for leaks.
- bb. Information required by §60.486(d) for the design requirements for closed vent system/control device.

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- cc. Information required by §60.486(e) for the equipment.
- dd. Information required by §60.486(f) for the valves.
- ee. Information required by §60.486(g) for the valves.
- ff. Information required by §60.486(h).
- gg. Requirements to show that equipment is not in VOC service as provided by §60.486(j).

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**SN-856 - Facility Tanks – Plantwide Applicability Limit (PAL)
 SN-858t – Tier 2 Fugitives and Tanks VOC Bubble**

Source Description

In order to demonstrate compliance with the emission limits for the tanks, the facility has decided to operate under a Plantwide Applicability Limit (PAL). The PAL is meant to allow the facility flexibility in operation and production while at the same time limiting the aggregate emissions from the tanks. The following is a summary of all tanks (including Tier II tanks, SN-858t) included in the PAL and the applicable regulations.

For simplicity, all of the tanks are described in the following table.

Table 38 – Tank Type Key

FCR	Fixed Cone Roof
FDR	Fixed Dome Roof
FFR	Fixed Flat Roof
EFR	External Floating Roof
IFR	Internal Floating Roof
OR	Open Roof Tank
HOR	Horizontal Tank

Table 39 – Tank Description

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-3	FCR	1950	3,320	---
T-4	FCR	1953	4,890	---
T-7	EFR	1999	20,000	Kb
T-11	FCR	1959	4,930	---
T-12	FCR	1955	4,930	---
T-14	FCR	1942	2,997	---
T-15	FCR	1942	2,997	---

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-16	FCR	1950	4,412	---
T-17	FCR	1940	3,672	---
T-18	FCR	1949	3,160	---
T-19	FCR	2002	2,000	Kb
T-22	FCR	1953	1,930	---
T-23	FCR	1953	1,930	---
T-24	FCR	1999	3,059	UU see notes ⁱⁱⁱ
T-25	FCR	1940	14,940	---
T-27	FCR	1950	3,553	---
T-36	IFR	1953	4,890	---
T-39	FCR	1958	4,890	---
T-40	FCR	1940	3,672	---
T-41	FCR	2005	3,672	UU
T-46	HOR	1933	752	---
T-48	FCR	1923	1,120	---
T-49	FCR	1923	1,120	---
T-50	FCR	1937	9,984	---
T-51	FCR	1940	11,748	---
T-54*	FDR	1922	15,090	---
T-55	FFR	1923	15,090	---
T-58	FFR	1952	10,120	---
T-59	FCR	2002	8,200	Kb

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-61	EFR	1949	20,160	---
T-62	EFR	1949	20,140	---
T-63	FCR	1957	8,602	---
T-64	IFR	1957	10,120	---
T-65	EFR	1954	10,120	---
T-70	FCR	1935	976	---
T-71	FCR	1935	976	---
T-72	FCR	1950	900	---
T-73	FCR	1950	900	---
T-74	FCR	1950	900	---
T-76	FCR	1938	36,293	---
T-77	FCR	1945	100	---
T-78	FCR	1999	5,000	UU
T-82	FCR	2004	20,081	---
T-84	FCR	1953	10,120	---
T-85	IFR	1954	10,120	---
T-88	EFR	1987	20,120	Kb
T-89	EFR	1948	20,120	---
T-96	FCR	1940	990	---
T-97	FCR	1940	990	---
T-98	FCR	1940	990	---
T-99	FCR	1940	1,008	---

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-101	FCR	1922	54,990	---
T-102	FCR	1922	55,236	---
T-103	EFR	1995	50,000	Kb
T-104	FCR	1923	55,500	---
T-105	FCR	1923	64,310	---
T-107	FCR	1923	55,140	---
T-108*	IFR	1982	55,447	Ka
T-109*	IFR	1982	55,367	Ka
T-110	FCR	1928	55,628	---
T-111	FCR	1936	55,755	---
T-112*	FCR	2005	151,065	UU see notes ⁱⁱⁱ
T-113*	EFR	2003	50,000	Kb
T-114	FCR	1923	54,720	---
T-115	FCR	1923	54,601	---
T-116	FCR	1923	55,050	---
T-117	FCR	1923	55,000	---
T-118	FCR	1944	54,813	---
T-119*	FCR	1940	55,140	---
T-120	IFR	1949	80,419	---
T-121*	FCR	1949	80,440	---
T-122*	FCR	2953	80,440	---

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-123	EFR	1949	80,377	---
T-124	EFR	1959	54,432	---
T-125	EFR	1953	55,960	---
T-126	EFR	1953	55,960	---
T-128	EFR	1959	81,216	---
T-129	FCR	1937	2,546	---
T-142	FCR	1982	2,000	see notes ^{iv}
T-143	FCR	1982	2,000	see notes ^{iv}
T-145	FCR	1950	241	---
T-162	FCR	1951	2,050	---
T-165	HOR	1923	1,120	---
T-166	HOR	1923	1,120	---
T-167	FCR	1940	1,120	---
T-168	FCR	1940	1,331	---
T-170	FCR	1950	644	---
T-171	FCR	1950	644	---
T-173	HOR	1945	420	---
T-175	FCR	1940	5,128	---
T-176	FCR	1940	5,128	---
T-180	FCR	1959	300	---
T-188	FCR	1981	5,060	Ka
T-190	HOR	1940	158	---

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-199	FCR	1957	1,893	---
T-200	FCR	1936	2,180	---
T-201	HOR	2004	500	---
T-217	HOR	1964	52	---
T-219	FCR	1967	56,000	---
T-226	FCR	1936	273	---
T-228	FCR	1936	273	---
T-240	FCR	1953	3,036	---
T-241	FCR	1953	2,775	---
T-242	FCR	1953	2,688	---
T-243	FCR	1953	3,279	---
T-244	FCR	1953	2,088	---
T-245	IFR	1953	3,132	---
T-246	IFR	1953	3,107	---
T-247*	IFR	2003	5,130	Kb
T-262	FCR	1938	5,061	---
T-263	FCR	1938	5,061	---
T-264	FCR	1938	5,061	---
T-265	FCR	1938	5,061	---
T-270	FCR	1941	9,384	---
T-271	FCR	1941	9,240	---
T-272	FCR	1986	1,000	see notes ⁱⁱⁱ

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-273	FCR	1986	1,000	see notes ⁱⁱⁱ
T-274	FCR	1986	1,000	see notes ⁱⁱⁱ
T-306	FCR	1952	133	---
T-310	FCR	1950	992	---
T-311	FCR	1950	54	---
T-312	FCR	1950	54	---
T-313	FCR	1950	54	---
T-314	FCR	1950	52	---
T-315	FCR	1950	52	---
T-319	FCR	1950	286	---
T-320	FCR	1950	286	---
T-321	FCR	1950	286	---
T-322	FCR	1950	286	---
T-323	FCR	1950	286	---
T-324	FCR	1992	286	see notes ^v
T-325	FCR	1950	286	---
T-326	FCR	1950	286	---
T-327*	FCR	1950	286	---
T-328	FCR	1950	286	---
T-329	FCR	1950	286	---
T-330	FCR	1950	286	---
T-331	FCR	1950	286	---

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-332	FCR	1950	286	---
T-333	FCR	1950	286	---
T-335	FCR	1950	95	---
T-336	FCR	1950	95	---
T-337	FCR	1950	95	---
T-338	FCR	1950	95	---
T-339	FCR	1950	95	---
T-340	FCR	1961	504	---
T-348	FCR	1968	5,275	---
T-349	FCR	1968	5,279	---
T-350	FCR	1954	1,382	---
T-351	FCR	1954	1,382	---
T-352	FCR	1954	1,382	---
T-353	FCR	1954	1,382	---
T-354	FCR	1954	1,386	---
T-355	FCR	1959	1,006	---
T-356	FCR	1961	285	---
T-360	IFR	1957	15,120	---
T-361	IFR	1957	15,120	---
T-368	FCR	1966	10,120	---
T-371	IFR	1959	10,120	---
T-372	IFR	2003	10,120	Kb

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-382	FCR	2000	5,000	UU see notes ⁱⁱⁱ
T-383	FCR	2000	5,000	UU see notes ⁱⁱⁱ
T-384	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-385	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-386	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-387	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-410	FCR	circa-1945	80,760	---
T-411	FCR	circa-1945	80,760	---
T-412	FCR	circa-1945	80,760	---
T-413	FCR	circa-1945	80,760	---
T-414	FCR	circa-1945	80,760	---
T-432	FCR	1978	2,025	see notes ^{iv}
T-520	FCR	1950	55,000	---
T-521	EFR	1950	55,000	---

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-524	FCR	1951	55,000	---
T-525	EFR	1951	55,000	---
T-530	FCR	1951	55,000	---
T-532	IFR	1981	32,784	Ka
T-538	FCR	1989	24	see notes ^{vi}
T-539	FCR	1989	24	see notes ^{vi}
T-540	HOR	1987	242	---
T-544	FCR	1991	5,250	see notes ⁱⁱⁱ
T-548	FCR	1993	100,000	see notes ⁱⁱⁱ
T-549	FCR	1994	143	see notes ^{vi}
T-550	HOR	1985	48	see notes ^{vi}
T-551	HOR	1994	24	see notes ^{vi}
T-552	HOR	1996	242	see notes ^{vi}
T-553	FCR	1999	1,500	see notes ⁱⁱⁱ
T-570	EFR	1959	125,000	---
T-600	HOR	1994	48	see notes ^{vi}
T-601	HOR	1994	24	see notes ^{vi}
T-602	HOR	1994	24	see notes ^{vi}
T-603	HOR	1995	24	see notes ^{vi}
T-604	HOR	1994	13	see notes ^{vi}
T-605	HOR	1996	13	see notes ^{vi}
T-606	HOR	1996	13	see notes ^{vi}

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SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-607	HOR	1990	36	see notes ^{vi}
T-608	HOR	1987	190	see notes ^{vi}
T-609	HOR	1995	143	see notes ^{vi}
T-610	FCR	1980	8	see notes ⁱⁱ
T-611	FCR	1995	190	see notes ^{vi}
T-612	FCR	1995	71	see notes ^{vi}
T-613	HOR	2000	75	see notes ^{vi}
T-616	FCR	2000	48	see notes ^{vi}
T-618	FCR	2001	24	see notes ^{vi}
T-619	HOR	2001	48	see notes ^{vi}
T-620	HOR	2001	24	see notes ^{vi}
T-621	HOR	2001	13	see notes ^{vi}
T-622	HOR	2001	24	see notes ^{vi}
T-New	FCR	2007	150,000	UU
T-998	IFR	2008	80,419	Kb
*Denotes a tank associated with the Tier II project.				

NSPS Regulation Notes

- i. Reserved
- ii. Pursuant to 40 C.F.R. 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, Tank T-610 is not an affected source because it is smaller than 40,000 gallons.
- iii. Pursuant to 40 C.F.R. 60, Subpart Kb- *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tanks T-24, T-113, T-272

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through T-274, T-382 through T-387, T-544, T-548, and T-553 are exempt from the control requirements of Subpart Kb by §60.112b(a) because they store a liquid with a maximum true vapor pressure less than 5.2 kPa (0.75 psia) (see Appendix B).

- iv. Pursuant to 40 C.F.R. 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, T-142, T-143, T-188 and T-432 are not affected facilities because they do not store volatile organic liquids with vapor pressure greater than 1.5 psia (10.3 kPa) (see Appendix A).
- v. Pursuant to 40 C.F.R. 60, Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tank T-324 is not an affected source under §60.110(a) because it does not contain a VOL (see Appendix B).
- vi. Pursuant to 40 C.F.R. 60, Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tank's T-538, T-539, T-549 to T-552, T-600 to T-609, T-611, T-612, T-613, T-616, T-618, T-619, T-620, T-621, and T-622 are not affected sources because they are smaller than 75 m³.
- vii. All other tanks, which are not listed above except tanks T-7, T-19, T-59, T-88, T-103, T-108, T-109, T-113, T-188, T-247, T-372, and T-532, are not subject to 40 C.F.R. 60, Subparts K, Ka, or Kb. The NSPS requirements for tanks these tanks are outlined in the Specific Conditions.
- viii. All tanks have been classified as a Group I or Group II storage vessel in accordance with the provisions of 40 C.F.R. 63, Subpart CC-*National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*. Subpart CC is outlined in the Plantwide Conditions of this permit.

Specific Conditions

- 137. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by completing an annual emissions inventory, refinery crude feed rate limits, and maximum vapor pressure restrictions. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 40 – Tank Criteria Emissions

SN	Pollutant	lb/hr	tpy
856	PM ₁₀	4.4	1.4
	VOC	9,233.4	2,934.2
	CO	207.2	65.9
858t	VOC	*	322.5
* Short term emissions from Tier II tanks (SN-858t) are subject to the short-term limit for all facility tanks found under SN-856.			

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138. The facility shall store only products with calendar month average true vapor pressure equal to or less than the vapor pressure listed for each tank in the following table. [§19.501 of Regulation 19 and 40 C.F.R. §70.6]

Table 41 – Tank Vapor Pressure

SN	Maximum Vapor Pressure (PSI)
PAL	---
T-3	14.7 ^D
T-4	14.7 ^D
T-7	11.1 ^{FR}
T-11	14.7 ^D
T-12	14.7 ^D
T-14	14.7 ^D
T-15	14.7 ^D
T-16	14.7 ^D
T-17	14.7 ^D
T-18	14.7 ^D
T-19	0.75 ^{NC}
T-20	removed from service, 2004
T-21	removed from service, 2004
T-22	14.7 ^D
T-23	14.7 ^D
T-24	0.75 ^{NC}
T-25	14.7 ^D
T-27	14.7 ^D
T-36	11.1 ^{FR}
T-39	14.7 ^D
T-40	14.7 ^D
T-41	14.7 ^C
T-46	14.7 ^D
T-48	14.7 ^D
T-49	14.7 ^D

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SN	Maximum Vapor Pressure (PSI)
T-50	14.7 ^D
T-51	14.7 ^D
T-54	14.7 ^D
T-55	14.7 ^D
T-58	14.7 ^D
T-59	0.75 ^{NC}
T-61	11.1 ^{FR}
T-62	11.1 ^{FR}
T-63	14.7 ^D
T-64	11.1 ^{FR}
T-65	11.1 ^{FR}
T-70	14.7 ^D
T-71	14.7 ^D
T-72	14.7 ^D
T-73	14.7 ^D
T-74	14.7 ^D
T-76	14.7 ^D
T-77	14.7 ^D
T-78	14.7 ^D
T-82	0.75 ^{NC}
T-84	14.7 ^D
T-85	11.1 ^{FR}
T-88	11.1 ^{FR}
T-89	11.1 ^{FR}
T-96	14.7 ^D
T-97	14.7 ^D
T-98	14.7 ^D
T-99	14.7 ^D
T-101	14.7 ^D
T-102	14.7 ^D

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SN	Maximum Vapor Pressure (PSI)
T-103	11.1 ^{FR}
T-104	14.7 ^D
T-105	14.7 ^D
T-107	14.7 ^D
T-108	1.5 ^{NC}
T-109	1.5 ^{NC}
T-110	14.7 ^D
T-111	14.7 ^D
T-112	0.75 ^{NC}
T-113	11.1 ^{FR}
T-114	14.7 ^D
T-115	14.7 ^D
T-116	14.7 ^D
T-117	14.7 ^D
T-118	14.7 ^D
T-119	14.7 ^D
T-120	11.1 ^{FR}
T-121	14.7 ^D
T-122	14.7 ^D
T-123	11.1 ^{FR}
T-124	11.1 ^{FR}
T-125	11.1 ^{FR}
T-126	11.1 ^{FR}
T-128	11.1 ^{FR}
T-129	14.7 ^D
T-142	1.5 ^{NC}
T-143	1.5 ^{NC}
T-145	14.7 ^D
T-162	14.7 ^D
T-165	14.7 ^D

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SN	Maximum Vapor Pressure (PSI)
T-166	14.7 ^D
T-167	14.7 ^D
T-168	14.7 ^D
T-170	14.7 ^D
T-171	14.7 ^D
T-173	14.7 ^D
T-175	14.7 ^D
T-176	14.7 ^D
T-180	14.7 ^D
T-188	1.5 ^{NC}
T-190	14.7 ^D
T-199	14.7 ^D
T-200	14.7 ^D
T-201	14.7 ^C
T-217	14.7 ^D
T-219	14.7 ^D
T-226	14.7 ^D
T-228	14.7 ^D
T-240	14.7 ^D
T-241	14.7 ^D
T-242	14.7 ^D
T-243	14.7 ^D
T-244	14.7 ^D
T-245	11.1 ^{FR}
T-246	11.1 ^{FR}
T-247	11.1 ^{FR}
T-262	14.7 ^D
T-263	14.7 ^D
T-264	14.7 ^D
T-265	14.7 ^D

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SN	Maximum Vapor Pressure (PSI)
T-270	14.7 ^D
T-271	14.7 ^D
T-272	0.75 ^{NC}
T-273	0.75 ^{NC}
T-274	0.75 ^{NC}
T-306	14.7 ^D
T-310	14.7 ^D
T-311	14.7 ^D
T-312	14.7 ^D
T-313	14.7 ^D
T-314	14.7 ^D
T-315	14.7 ^D
T-319	14.7 ^D
T-320	14.7 ^D
T-321	14.7 ^D
T-322	14.7 ^D
T-323	14.7 ^D
T-324	4.0 ^{NC}
T-325	14.7 ^D
T-326	14.7 ^D
T-327	14.7 ^D
T-328	14.7 ^D
T-329	14.7 ^D
T-330	14.7 ^D
T-331	14.7 ^D
T-332	14.7 ^D
T-333	14.7 ^D
T-335	14.7 ^D
T-336	14.7 ^D
T-337	14.7 ^D

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SN	Maximum Vapor Pressure (PSI)
T-338	14.7 ^D
T-339	14.7 ^D
T-340	14.7 ^D
T-348	14.7 ^D
T-349	14.7 ^D
T-350	14.7 ^D
T-351	14.7 ^D
T-352	14.7 ^D
T-353	14.7 ^D
T-354	14.7 ^D
T-355	14.7 ^D
T-356	14.7 ^D
T-360	11.1 ^{FR}
T-361	11.1 ^{FR}
T-368	14.7 ^D
T-371	11.1 ^{FR}
T-372	11.1 ^{FR}
T-382	0.75 ^{NC}
T-383	0.75 ^{NC}
T-384	0.75 ^{NC}
T-385	0.75 ^{NC}
T-386	0.75 ^{NC}
T-387	0.75 ^{NC}
T-410	14.7 ^D
T-411	14.7 ^D
T-412	14.7 ^D
T-413	14.7 ^D
T-414	14.7 ^D
T-432	1.5 ^{NC}
T-520	14.7 ^D

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SN	Maximum Vapor Pressure (PSI)
T-521	14.7 ^D
T-524	14.7 ^D
T-525	14.7 ^D
T-530	14.7 ^D
T-532	11.1 ^{FR}
T-538	14.7 ^C
T-539	14.7 ^C
T-540	14.7 ^C
T-544	0.75 ^{NC}
T-548	0.75 ^{NC}
T-549	14.7 ^C
T-550	14.7 ^C
T-551	14.7 ^C
T-552	14.7 ^C
T-553	0.75 ^{NC}
T-570	14.7 ^D
T-600	14.7 ^C
T-601	14.7 ^C
T-602	14.7 ^C
T-603	14.7 ^C
T-604	14.7 ^C
T-605	14.7 ^C
T-606	14.7 ^C
T-607	14.7 ^C
T-608	14.7 ^C
T-609	14.7 ^C
T-610	14.7 ^C
T-611	14.7 ^C
T-612	14.7 ^C
T-613	14.7 ^C

SN	Maximum Vapor Pressure (PSI)
T-616	14.7 ^C
T-618	14.7 ^C
T-619	14.7 ^C
T-620	14.7 ^C
T-621	14.7 ^C
T-622	14.7 ^C
T-New	0.75 ^{NC}
T-998	11.1 ^{FR}

- 14.7^D No limit or restriction on v.p. - the construction date is prior to the NSPS date. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
- 14.7^C No limit or restriction on v.p. - capacity of tank is below the NSPS applicability capacity of 19,800 gals for NSPS Kb or 40,000 gals for NSPS K & Ka. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
- 14.7^V No limit or restriction on v.p. - the product stored does not meet the definition of a VOL under NSPS Kb. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
- 14.7^P No limit or restriction on v.p. - the product does not meet the definition of a petroleum liquid under NSPS Ka. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
- x^{NC} V. P. restricted or limited - No Controls required; v.p. of product is below the limit that requires controls : 0.75 psia (5.2 kPa) for NSPS Kb (for tanks > 40,000 gal.); 4.0 psia (27.6 kPa) for NSPS Kb (for tanks with capacities between 20,000 and 40,000 gallons); or 1.5 psia (10.3 kPa) for NSPS K & Ka. See 40

C.F.R. §60.112b(a) and 60.112a(a).

x^{FR} V. P. restricted or limited - v.p. of the product cannot exceed 11.1 psia (76.6 kPa) based on using a Floating Roof as the control standard as required by the NSPS and/or MACT standard.

139. Solely for purposes of demonstrating compliance with the Tank PAL emission limits, the facility shall not exceed a total refinery crude feed rate of 100,000 barrels per day and a total of 36.6 MM bbls per consecutive twelve-month period. This limit is solely to demonstrate compliance with the emission limits in Specific Condition 137 and does not establish any production rate, design capacity or other limitation. [§19.705 of Regulation 19 and 40 C.F.R. §70.6]
140. The facility shall maintain records of the total refinery crude feed rate to the facility on a daily basis and on a twelve-month rolling basis, both updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
141. The facility shall conduct an annual inventory of emissions of the pollutants listed in Specific Condition 137. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), and shall be submitted to the Department at the following address no later than August 1 of each year. If the annual emissions inventory demonstrates that the permittee has exceeded any permit limit, it shall not be a violation of the permit provided that the exceedance is due to a change in a published emission factor upon which the permittee relied in setting the permitted limit or new published emission factors. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
- Arkansas Department of Environmental Quality
Air Division
Attn: Compliance Inspector Supervisor
Post Office Box 8913
Little Rock, AR 72219
142. Under the terms of 40 CFR, Part 60, Subpart Ka-Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984, tanks T-108, T-109, 142, 143, 188, and 432 do not store a petroleum liquid with a true vapor pressure of 10.3 kPa (1.5 psia) or greater; and therefore are exempt from control requirements of Subpart Ka pursuant to 60.112a(a) (see Appendix A). Therefore, any petroleum liquid stored in these tanks shall have a vapor pressure less than 10.3 kPa (1.5 psia). Pursuant to 60.115a(a), the facility must maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period. [19.304 of Regulation 19 and 40 CFR 60.112a]
143. Tank T-532 is an affected facility under the terms of 40 CFR 60, Subpart Ka- Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984. However, in accordance with 40 C.F.R., Part 63, Subpart CC- National Emission Standards for

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144. Under the terms of 40 CFR Part 60 Subpart Kb-Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, tanks T-7, T-88, T-103, T-113, T-247, T-372, T-998 are affected facilities. The tanks are subject to the Subpart Kb requirements, which are summarized below (for the full regulation, see Appendix B). [§19.304 of Regulation 19, and 40 CFR §60.110b]
- a. Tank T-7, T-88, T-103, and T-113 have been equipped with external floating roofs as described in §60.112b(a)(2). [§60.112b(a)]
 - b. Tanks T-247, T-372, and T-998 have been equipped with internal floating roofs as described in §60.112b(a)(1). [§60.112b(a)]
 - c. Tank T-7, T-88, T-103, and T-113 have a mechanical shoe seal. Except as provided in §60.113b(b)(4), the seals shall completely cover the annular space between the edge of the floating roof and the tank wall. [§60.112b(a)(2)(i)(A)]
 - d. The secondary seals shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed by §60.113b(b)(4). [§60.112b(a)(2)(i)(B)]
 - e. Except for automatic bleeder vents and rim space vents, each opening in the floating roofs provides a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are gasketed. Each emergency roof drain is provided with a slotted membrane fabric cover that covers at least 90 percent of the opening of the area. [§60.112b(a)(2)(ii)]
 - f. The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. [§60.112b(a)(2)(ii)]
 - g. Tanks T-7, T-88, T-103, T-113, T-247, and T-372 shall meet the testing requirements of §60.113b(b). [§60.113b]
 - h. The facility has determined and will continue to determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the

secondary seal and the wall of the storage vessel as prescribed by §60.113b(b)(1)(i).
[§60.113b(b)(1)]

- i. Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed at least once every 5 years after the date of the initial fill. [§60.113b(b)(1)(i)]
- j. Measurements of gaps between the tank wall and the secondary seal shall be performed at least once per year after the date of the initial fill. [§60.113b(b)(1)(ii)]
- k. If these sources cease to store a VOL for a period of one year or more, subsequent introduction of VOL into the vessels shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section. [§60.113b(b)(1)(iii)]
- l. The facility shall determine gap widths and areas in the primary and secondary seals individually by the procedures outlined in (i), (ii), and (iii) as follows: [§60.113b(b)(2)]
 - i. The facility shall measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports. [§60.113b(b)(2)(i)]
 - ii. The facility shall measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location. [§60.113b(b)(2)(ii)]
 - iii. The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance. [§60.113b(b)(2)(iii)]
- m. The facility shall add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4).
[§60.113b(b)(3)]
- n. The facility shall make necessary repairs or empty the storage vessels within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4)(i) and (ii). [§60.113b(b)(4)]
- o. The accumulated area of gaps between the tank wall and the mechanical shoe or liquid mounted primary seal shall not exceed 212 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm. [§60.113b(b)(4)(i)]
- p. One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.
[§60.113b(b)(4)(i)(A)]
- q. There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
[§60.113b(b)(4)(i)(B)]

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- r. The secondary seal is to meet the requirements of the following: [§60.113b(b)(4)(ii)]
 - i. The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in (b)(2)(iii). [§60.113b(b)(4)(ii)(A)]
 - ii. The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm. [§60.113b(b)(4)(ii)(B)]
 - iii. There are to be no holes, tears, or other openings in the seal or seal fabric. [§60.113b(b)(4)(ii)(C)]
- s. If a failure that is detected during inspections required by paragraph (b)(1), of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required by §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [§60.113b(b)(4)(iii)]
- t. The facility shall notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present. The Department has exercised its authority to grant permission for the 30-day notification period to be shortened to 5 days as indicated by Plantwide Condition #10 (FF) and (GG). [§60.113b(b)(5)]
- u. The facility shall visibly inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed. [§60.113b(b)(6)]
- v. If an external floating roof has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the facility shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL. [§60.113b(b)(6)(i)]
- w. For all inspections required by (b)(6), the facility shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the facility could not have known about the inspection 30 days in advance of refilling the tank, the facility should notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received at least 7 days prior to the refilling. The Department has exercised its authority to grant permission for the 30-day and 7-day notification periods to be shortened to 5 days as indicated by Plantwide Condition #10 (FF) and (GG). [§60.113b(b)(6)(ii)]

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- x. The facility shall keep records of tanks T-7, T-88, T-103, T-113, T-247 and T-372 as specified in § 60.115b(b)(3). The facility shall keep copies of all reports and records required by this section for at least 2 years. [§60.115b(b)]
 - y. The facility has or shall furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(a)(2), (b)(3), and (b)(4). [§60.115b(1)]
 - z. Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), the facility shall furnish the Administrator with a report that contains: [§60.115b(b)(2)]
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in § 60.113b(b)(2) and (b)(3).
 - aa. The facility shall keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain: [§60.115b(b)(3)]
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in § 60.113b(b)(2) and (b)(3).
 - bb. After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in (b)(2) and the date the vessel was emptied or the repairs made and date of repair. [§60.115b(b)(4)]
 - cc. The facility shall keep copies of all records of tanks T-7, T-88, T-103, T-113, T-247 and T-372 as required by §60.116b for at least 2 years. As an exception, the record required by §60.116b(b) shall be kept for the lives of the sources. [§60.116b(a)]
 - dd. The facility shall keep readily accessible records showing the dimensions of each vessel and an analysis showing the capacity of each vessel. [§60.116b(b)]
 - ee. The facility shall maintain for each tank a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period. [§60.116b(c)]
 - ff. The facility may determine the maximum true vapor pressure as described in §60.116b(e)(1), (e)(2) and (e)(3). [§60.116b(e)]
145. Tanks T-19, T-24, T-59, T-272 through T-274, T-382 through T-387, T-544, T-548, and T-553 are exempted from the control requirements of Subpart Kb pursuant to 40 C.F.R. 60.112b(a) because they have capacities greater than 151 m³ and store a liquid with a maximum true vapor

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pressure less than 5.2 kPa (0.75 psia). Therefore, any volatile organic liquid stored in these tanks shall have a vapor pressure less than 5.2 kPa (0.75 psia). These tanks are also subject to the following subpart Kb requirements, which are summarized below (for the full regulation, see Appendix B). [§19.304 of Regulation 19 and 40 CFR §60.112b(a)]

- a. The facility shall as specified in §60.116b(a) keep the records as required by §60.116b(b) for the lives of the facilities.
 - b. In accordance with §60.116b(b), the facility shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.
 - c. In accordance with §60.116b(d), the facility shall notify the Department within 30 days when the maximum true vapor pressure exceeds 5.2 kPa (0.75 psia).
 - d. Pursuant to §60.116b(e), the facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3).
146. Tank T-324 does not store a volatile organic liquid with a vapor pressure of 15.0 kPa (4.0 psia); and, therefore is exempt from the control requirements of Subpart Kb. As such, any volatile organic liquid stored in this tank shall have a vapor pressure less than 15.0 kPa (4.0 psia). This tank is also subject to the Subpart Kb requirements, which are summarized below (for the full regulation, see Appendix B). [§19.304 of Regulation 19 and 40 CFR §60.110b(c)]
- a. The facility shall as specified in §60.116b(a) keep the records as required by § 60.116b(b) for the lives of the facilities.
 - b. In accordance with §60.116b(b), the facility shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.
 - c. In accordance with §60.116b(d), the facility shall notify the Department within 30 days when the maximum true vapor pressure exceeds 15 kPa (4.0 psia).
 - d. Pursuant to §60.116b(e), the facility may determine the maximum true vapor pressure as described in §60.116b(e)(1), (e)(2) and (e)(3).
147. Under the terms of 40 CFR Part 60 Subpart UU- Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture, tanks T-24, T-41, T-112, T-382, T-383, T-384, T-385, T-386, T-387, and T-New are affected facilities. As such, in accordance with 60.472(c), the tank(s) shall not exhaust gases with an opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being cleared. [§19.304 of Regulation 19, and 40 CFR §60.470]
148. Under the terms of 40 CFR Part 63 Subpart LLLLL- National Emission Standard for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing, tanks T-23, T-78, T-96, T-98, T-99, T-162, T-175, T-176, T-348, T-354 and T-544 are affected facilities. Each of the listed tanks is considered Group 2, and as such, in accordance with Table 1 to Subpart LLLLL,

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the tank(s) shall not exhaust gases with an opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being cleared. [§19.304 of Regulation 19, and 40 CFR §63.8684(a)]

149. Records shall be kept onsite of any activity related to construction, reconstruction, or modification of any of the tanks listed in this section. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

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SN-863 - Boiler Feedwater Pump

Source Description

One additional diesel-fired Boiler feed water pump rated at 475 hp-hr is permitted in association with the boiler replacement project.

Specific Conditions

150. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the operating limits of this section. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 42 - Boiler Feedwater Pump Criteria Emissions

SN #	Source Description	Pollutant	lb/hr	tpy
863	Boiler feedwater pump	PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.5	0.2
		CO	1.8	0.5
		NO _x	22.8	5.7

151. The permittee shall not operate the Boiler feedwater pump more than 500 hours per 12 consecutive months. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
152. The facility shall not exceed 5% opacity from the sources in this section while burning pipeline quality natural gas or NSPS Subpart J quality gas. Compliance with this limit shall be demonstrated by burning pipeline quality natural gas or other refinery fuel gas with an H₂S concentration less than 1,500 ppmvd. If the H₂S concentration exceeds 1500 ppmvd, then the facility shall comply with Specific Condition #153. [§18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
153. During those times in which the H₂S content of the refinery fuel gas combusted on-site exceeds 1500 ppmvd, the facility shall conduct an opacity observation for those sources which are permitted to combust NSPS Subpart J quality gas. These observations shall be conducted by someone who is familiar with the visible emissions from these sources. Any sources which generate visible emissions during these periods shall be considered to be in violation of the 5% opacity standard for that source. Records of these observations shall be maintained on-site, and shall be made available to the Department upon request. These records shall indicate the date and time of the observation, the name of the person making the observation, whether or not any visible emissions are detected, and a list of any sources (by SN) for which visible emissions were noted. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

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154. The permittee shall maintain records of the number of hours of operation of SN-862. Records shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. A 12-month rolling total shall be kept with these records. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

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Plantwide Applicability Limit (PAL) for Other Air Emissions

In order to demonstrate compliance with Regulation 18, § 18.801, the facility will operate under a Plantwide Applicability Limit (PAL) for other air emissions. The Department reviewed the emissions and determined that compliance with these emission limitations will constitute compliance with the terms of §18.801 of Regulation 18 for the sources identified in this permit. This PAL is meant to allow the facility flexibility in operation and production while at the same time limiting the total amount of air emissions from the facility.

Specific Conditions

155. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by an annual emissions inventory and compliance with the feed rate, physical and operational limits in this Permit. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Table 43 - Plantwide Applicability Limit (PAL) for Other Air Emissions

Description	Pollutant*	Allowable Emission Rate TPY
Plantwide Applicability Limit ¹	Benzene	67.9
	Biphenyl	9.5
	1,3 Butadiene	5.1
	Carbon Disulfide	4.4
	Carbonyl Sulfide	4.5
	Cresol (mixed isomers)	14.0
	Cumene	10.2
	Diethanolamine	4.4
	Ethyl benzene	43.6
	Hexane	314.5
	Naphthalene	6.6
	Phenol	9.8
	Toluene	148.7
	2,2,4 Trimethylpentane	56.2

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Description	Pollutant*	Allowable Emission Rate TPY
	Xylene (mixed isomers)	341.8
	Ammonia	62.1
	Chlorine	26.7
	Hydrogen Chloride	48.6
	Sulfuric Acid	88.3
	Hydrogen Sulfide	364.3
	Perchloroethylene (tetrachloroethylene)	7.1
	Formaldehyde	4.9
	Particulate matter	884.3
*Other air contaminants may be emitted from the facility in very small quantities, which would be difficult to measure and report. No significant levels of unlisted air contaminants are allowable under this permit.		
¹The PAL does not include volatile organic compound (VOC) air emissions that are not hazardous air pollutants (HAP), as defined in 42 U.S.C. § 7412(b). The emissions of these non-HAP organic pollutants are captured and regulated by the VOC emission limits for the individual sources in this Permit.		

156. The facility shall conduct an annual inventory of emissions of the pollutants listed in Specific Condition #155. The emissions inventory shall be calculated using methods relied upon in establishing the emission limits in Specific Condition #155. The facility may use different methodologies than those relied upon in establishing the limits; however, any change in a methodology shall be submitted to the Department and approved in advance of submission of the annual emission inventory. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), beginning in year 2003, and shall be submitted to the Department at the following address no later than August 1 of each year. If an annual emissions inventory is requested by the Department before August 1, the permittee shall have until August 1 to submit the requested information. This condition does not apply to emissions inventories requested by the Department pursuant to §19.705(c) and 40 CFR §51.321. [§18.1004 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

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 Air Division
 Attn: Compliance Inspector Supervisor
 Post Office Box 8913

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157. If the annual emissions inventory demonstrates that the permittee has exceeded any PAL limit, it shall not be considered a violation of the permit provided that the exceedance is due to either a change in a published emission factor upon which permittee relied in setting the permitted limit, new emissions factors or the development of other emissions data (including site specific test data), which could affect the estimated emission rates. [§18.1004 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Section V: PLANT WIDE CONDITIONS

1. The permittee will notify the Administrator in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation No. 19 §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Administrator may cancel all or part of this permit. [Regulation No.19 §19.410(B) and 40 CFR Part 52, Subpart E]
3. The permittee must test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) New Equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start-up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee will submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation No.19 §19.702 and/or Regulation No. 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
4. The permittee must provide: [Regulation No.19 §19.702 and/or Regulation No.18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
 - a. Sampling ports adequate for applicable test methods
 - b. Safe sampling platforms
 - c. Safe access to sampling platforms
 - d. Utilities for sampling and testing equipment.
5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee will maintain the equipment in good condition at all times. [Regulation No.19 §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation No. 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
7. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such

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allowance according to the procedures established in regulations promulgated under Title IV of the Act. [Regulation No. 26 §26.701 and 40 CFR 70.6(a)(4)]

8. Pipeline quality natural gas is that which meets the tariff requirements of any major transmission company. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
9. The facility is subject to 40 CFR Part 61 Subpart FF – *National Emission Standards for Benzene Waste Operations* because it is a petroleum refinery (see Appendix E). [§19.304 of Regulation 19 and 40 CFR §61.340(a)]
 - a. The facility has identified itself as having total annual benzene quantity from facility waste of less than 10 Mg/yr. The facility shall follow any applicable requirements of § 61.342(a).
 - b. The facility shall keep the records required by § 61.356(a) and (b).
 - c. The facility shall follow the reporting requirements of § 61.357(c).
10. The facility is subject to the provisions of 40 CFR Part 63 Subpart CC-*National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*, which are summarized below (for the full regulation, see Appendix I).
 - a. For the purpose of this subpart, the affected source shall comprise all emission points, in combination, listed in § 63.640(c)(1) through (c)(7) that are located at a single refinery plant site. *Note: (c)(6) does not apply.*
 - i. All miscellaneous process vents from petroleum refining process units meeting the criteria in § 63.640 (a);
 - ii. All storage vessels associated with petroleum refining process units meeting the criteria in § 63.640(a);
 - iii. All wastewater streams and treatment operations associated with petroleum refining process units meeting the criteria in § 63.640(a);
 - iv. All equipment leaks from petroleum refining process units meeting the criteria in § 63.640(a);
 - v. All gasoline loading racks classified under Standard Industrial Classification code 2911 meeting the criteria in § 63.640(a);
 - vi. All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery meeting the criteria in § 63.640(a).
 - b. Pursuant to § 63.640(d), the affected source does not include the emission points listed in paragraphs (d)(1) through (d)(5).

- i. Stormwater from segregated stormwater sewers;
 - ii. Spills;
 - iii. Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in § 63.641 of this subpart, for less than 300 hours during the calendar year.
 - iv. Catalytic cracking unit and catalytic reformer catalyst regeneration vents, and sulfur plant vents.
 - v. Emission points routed to a fuel gas system, as defined in § 63.641 of this subpart. No testing, monitoring record keeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.
- c. The owner or operator shall keep a log of the storage vessels in § 63.640(e)(1) and (e)(2) that are subject to Subpart CC.
- d. The owner or operator shall keep a log of the miscellaneous process vents from distillation units in § 63.640(f)(1) through (f)(5) that are subject to Subpart CC.
- e. The facility shall keep a log of the processes specified in paragraphs § 63.646(g)(1) through (g)(7) that are exempt from Subpart CC.
- f. Sources subject to Subpart CC shall achieve compliance with the subpart by the dates specified in § 63.640(h).
- g. Sources that are added, reconstructed, have additions, or are otherwise modified shall achieve compliance in accordance with § 63.640(i), (j), and (k).
- h. If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, or gasoline loading rack that meets the criteria in § 63.640 (c)(1) through (c)(7) is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emission point(s) (as defined in § 63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to § 63.640 (i) or (j), the requirements in § 63.640 (l)(1) through (l)(3) shall apply. The facility shall keep a log to show that it has complied with the provisions of this section.
- i. If a change that does not meet the criteria in § 63.640(l) is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in § 63.641), then the owner or operator shall comply with the requirements of this subpart for existing sources for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1. A compliance schedule for the change shall be submitted to the Administrator in accordance with § 63.640(m)(1) through (3).

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- j. The following shall apply to the facility for the overlap of subpart CC with other regulations for storage vessels in § 63.640(n)(1) through (7).

Table 44 - Overlap with Existing Federal Regulations - Storage Vessels

Existing Regulation	Source	Group	Comply with	Comments
40 C.F.R. 60, Subpart Kb	Existing	Group 1 Group 2	40 C.F.R. 60, Subpart Kb	
40 C.F.R. 60, Subpart Kb	New	Group 1	40 C.F.R. 63, Subpart CC	
40 C.F.R. 60, Subpart Kb (see comment)	New	Group 2	40 C.F.R. 60, Subpart Kb	If source is subject to control requirements in Subpart Kb, comply with Kb instead of CC.
40 C.F.R. 60, Subpart Kb (see comment)	New	Group 2	40 C.F.R. 63, Subpart CC	If source is not required to apply controls by Subpart Kb, comply with CC instead of Kb.
40 C.F.R. 60, Subpart K or Ka	New and Existing	Group 1	40 C.F.R. 63, Subpart CC	
40 C.F.R. 60, Subpart K or Ka	New and Existing	Group 2	40 C.F.R. 60, Subpart K or Ka	If source is subject to control requirements in Subparts K or Ka, comply with K or Ka instead of CC.
40 C.F.R. 60, Subpart K or Ka	New and Existing	Group 2	40 C.F.R. 63, Subpart CC	If source is not required to apply controls by Subparts K or Ka, comply with CC instead of K or Ka.

- k. The following shall apply to the facility for the overlap of subpart CC with other regulations for wastewater in § 63.640(o)(1) and (2).

Table 45 - Overlap with Existing Federal Regulations - Wastewater

Existing Regulation	Source	Group	Comply with	Comments
40 C.F.R. 60, Subpart QQQ	New and Existing	Group 1	40 C.F.R. 63, Subpart CC	
40 C.F.R. 61, Subpart FF	New and Existing	Group 1	40 C.F.R. 61, Subpart FF	
40 C.F.R. 63, Subpart G	New and Existing	Group 1 Group 2	40 C.F.R. 63, Subpart G, §§ 63.133-63.137, 63.140	Applies to equipment used in storage and conveyance of wastewater streams.

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		40 C.F.R. 61, Subpart FF, and 40 C.F.R. 63, Subpart G, §§ 63.138, 63.139	Applies to treatment and control of wastewater streams.
		40 C.F.R. 63, Subpart G, §§ 63.143-63.148	Applies to monitoring and inspections of equipment and recordkeeping and reporting requirements.

- l. After the compliance dates specified in § 63.640(h) equipment leaks that are also subject to the provisions of 40 C.F.R. 60 and 61 are required to comply only with the provisions of this subpart.
- m. The facility shall refer to Table 6 of Subpart CC in accordance with § 63.642(c) for in order to reference specific provisions of Subpart A of Part 63 that apply and those that do not apply.
- n. Pursuant to § 63.642(d), initial performance tests and initial compliance determinations shall be required only as specified in this subpart. A log showing compliance with §§ 63.642(d)(1) through (4) shall be kept.
- o. Pursuant to §63.642(e), each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed. Records for the most recent 2 years shall be retained onsite at the source or shall be accessible from a central location by computer. The remaining 3 years of records may be retained offsite. Records may be maintained in hard copy or computer- readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.
- p. Pursuant to §63.642(f), all reports required under this subpart shall be sent to the Administrator at the addresses listed in § 63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.
- q. Pursuant to §63.642(h), the owner or operator of a new source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of this section.
- r. Pursuant to §63.642(i), the owner or operator of an existing source shall demonstrate compliance with the emission standard in §63.642(g) by following the procedures specified in §63.642(k) for all emission points, or by following the emissions averaging compliance approach specified in §63.642(l) for specified emission points and the procedures specified in §63.642(k) for all other emission points within the source. The facility shall keep a log to demonstrate compliance with this provision.

- s. Pursuant to §63.642(j), the owner or operator of a new source shall demonstrate compliance with the emission standard in §63.642(h) only by following the procedures in §63.642(k). The owner or operator of a new source may not use the emissions averaging compliance approach. The facility shall keep a log to demonstrate compliance with this provision.
- t. The owner or operator of a Group 1 miscellaneous process vent as defined in § 63.641 shall comply with the requirements of either § 63.643(a)(1) or (a)(2). A log shall be kept to demonstrate compliance with these provisions.
- u. The facility shall keep a log to demonstrate compliance with the provisions of § 63.644(a) for Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in § 63.643(a).
- v. The facility shall keep a log to demonstrate how it has complied with § 63.644(c) which requires the owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with § 63.644(a) to follow additional constraints outlined in § 63.644(c).
- w. Pursuant to § 63.644(d), the owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in §63.654(f)(1)(3) shall be submitted in the Notification of Compliance Status report.
- x. Pursuant to § 63.644(e) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of this section. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in §63.654(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.
- y. The facility shall comply with the test measures and procedures for miscellaneous process vents in § 63.645.
- z. Pursuant to § 63.645(h), the owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. A log of these calculations and supporting assumptions shall be kept to demonstrate compliance with § 63.645.
- aa. The facility shall keep a log to demonstrate that the compliance determination for § 63.645(i) has been met.
- bb. The facility shall comply with the storage vessel provisions of § 63.646. Notices of Compliance Status Report shall be submitted to the Administrator as required by this section.

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- cc. Pursuant to §63.646(e), when complying with the inspection requirements of § 63.120 of subpart G of this part, owners and operators of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.
- dd. Pursuant to § 63.646(f), the paragraphs (f)(1), (f)(2), and (f)(3) of this section apply to Group 1 storage vessels at existing sources:
 - i. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.
 - ii. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.
 - iii. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
- ee. Pursuant to §63.646(g), failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.
- ff. The provisions of 40 CFR 63.646(l) provide state permitting agencies with the authority to waive or modify the notification requirements of 40 CFR §§ 63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii). The notification requirements of these sections are hereby modified as follows: Lion Oil shall provide notice, as required herein, by facsimile transmittal five (5) business days prior to the scheduled event in lieu of providing 30 days prior written notice to the Department. This written notice may be submitted electronically to the local district air inspector and the ADEQ Air Division Enforcement Branch Technical Assistance Manager.
- gg. The provisions of 40 CFR §63.654(h)(2)(C)(ii) provide state permitting agencies with the authority to waive or modify the notification requirements of 40 CFR §63.120(b)(1) or §63.120(b)(2) of Subpart G of part 63. The notification requirements of these sections are hereby modified as follows: Lion Oil shall provide notice, as required herein, by facsimile transmittal five (5) business days prior to the scheduled event in lieu of providing 30 days prior written notice to the Department. This written notice may be submitted electronically to the local district air inspector and the ADEQ Air Division Enforcement Branch Technical Assistance Manager.
- hh. The facility shall comply with the wastewater provisions of §63.647 where applicable. The facility shall maintain a log to demonstrate that it has complied with the requirements of this section.
- ii. The facility shall comply with the equipment leak standards of § 63.648. Portions of this section overlap with the requirements already listed for Subpart VV in the Fugitive Emissions (SN- 854) section of this permit. The facility may combine the requirements

of that section with this section and keep all necessary reports in one log. In any case, the facility shall keep a log to demonstrate compliance with this section.

- jj. Pursuant to § 63.648(h), each owner or operator of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years.
- kk. The facility shall comply with the gasoline loading rack provisions of § 63.650(a). The facility shall keep a log to demonstrate that all requirements of this section have been met.
- ll. The facility shall keep in a log, methods used and affected equipment for any of the emissions averaging provisions that are used in § 63.652. The facility shall also follow the requirements for § 65.653. Records for monitoring, recordkeeping, and implementation plans shall also be kept in the same log.
- mm. The facility shall comply with the provisions of § 63.654(a) and keep a log of how it has complied with those provisions.
- nn. The facility shall comply with the provisions of § 63.654(b) and keep a log of how it has complied with those provisions.
- oo. The facility shall comply with the provisions of § 63.654(d)(1) through (6) and keep a log of how it has complied with those provisions.
- pp. Pursuant to § 63.654(e), the facility shall submit the reports listed in paragraphs (e)(1) through (e)(3) except as provided in paragraph (h)(5) of this section, and shall keep records as described in paragraph (i) of this section.
 - i. A Notification of Compliance Status report as described in paragraph (f) of this section.
 - ii. Periodic Reports as described in paragraph (g) of this section.
 - iii. Other reports as described in paragraph (h) of this section.
- qq. The facility shall keep a log to show that it has complied with § 63.654(f)(1) through (6).
- rr. The facility shall keep a log to show that it has complied with the requirements of § 63.654(g)(1) through (g)(8).
- ss. The facility shall keep a log demonstrating that it has complied with the submittal requirements of § 63.654(h).
- tt. The facility shall keep a log of the records required by § 63.654(i).
- uu. All other information required to be reported under paragraphs § 63.654(a) through (h) shall be retained for 5 years.

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- vv. Compliance demonstrations begin on the first of the next calendar month following the beginning of the permit requirement. For those sources not subject to a rolling average requirement in the permits preceding AR-868-R0, rolling average requirements do not begin until twelve months after the issuance of this permit. Although on-going compliance with annual limits will be demonstrated with twelve-month rolling averages, violation of annual limits can only occur once per calendar year.
11. All sources specified as fuel gas combustion devices (See Specific Condition 1) under the provisions of 40 C.F.R. 60, Subpart J-*Standards of Performance for Petroleum Refineries* in the specific conditions of this permit are subject to the requirements outlined below (for the full regulation, see Appendix C): [§19.304 of Regulation 19 and 40 CFR §60.100]
- a. "NSPS Subpart J quality gas" or "Refinery fuel gas" is defined as any gas which is generated at a petroleum refinery and which is combusted, with the exception of gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. "Fuel gas" is defined as any gas which is generated at a petroleum refinery and which is combusted with the exception of gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. [§ 60.101(d)]
- b. The permittee shall not burn fuel gas that exceeds the concentration set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Subpart J. [§60.104]

Table 46 – Fuel Gas Sulfur Limits

Sources	Pollutant	mg/dscm	gr/dscf	ppmvd
All refinery Fuel Gas Combustion Devices	H ₂ S	230	0.10	162
	SO ₂	-	-	20

- c. The facility shall monitor emissions and operations by installing one of the following:
- i. An SO₂ CEMs on the fuel gas combustion exhaust [§60.105(a)(3)], or
- ii. An H₂S CEMS on the fuel gas before being combusted. [§60.105(a)(4)]
- d. Excess emissions that shall be determined and reported are defined as follows: [60.105(e)]
- i. All rolling 3-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under §60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or
- ii. All rolling 3-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under §60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

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- e. The test methods shall be conducted according to §60.106(e)(1) for H₂S CEMs or §60.106(e)(2) and §60.106(f)(1) for SO₂ CEMs. [§60.106]
 - f. The reporting and recordkeeping requirements shall be kept as required in §60.107(d), (e), and (f). [§60.107]
 - g. The combustion in a flare of a process upset gas or fuel gas that is released to the flares as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph. [§60.104(a)(1)]
12. The facility is subject to the provisions of 40 CFR Part 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, which are summarized below (for the full regulation, see Appendix I). [§19.304 and 40 CFR §63.1561]
- a. The permittee shall meet each applicable emission limitation in Table 1 of subpart UUU. If the catalytic cracking unit is subject to the NSPS for PM in §60.102 of, the permittee must meet the emission limitations for NSPS units. [§63.1564(a)(1)]
 - b. The permittee shall meet each applicable emission limitation in Table 8 of subpart UUU. If the catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in §60.103 of this chapter, the permittee must meet the emission limitations for NSPS units. [§63.1565(a)(1)]
 - c. The permittee shall meet each applicable operating limit in Table 2 and Table 9 of Subpart UUU. [§63.1564(a)(2), §63.1565(a)(2)]
 - d. The permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures of the plan. [§63.1564(a)(3), §63.1565(a)(3)]
 - e. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods referenced in §63.1564(b) and §63.1565(b). [§63.1564(b), §63.1565(b)]
 - f. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in §63.1564(c) and §63.1565(c). [§63.1564(c), §63.1565(c)]
 - g. The permittee shall meet each applicable emission limitation in Table 15 and Table 22 of Subpart UUU. [§63.1566(a)(1), §63.1567(a)(1)]
 - h. The permittee shall meet each applicable operating limit in Table 16 and Table 23 of Subpart UUU. [§63.1566(a)(2), §63.1567(a)(2)]
 - i. The permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures of the plan. [§63.1566(a)(3), §63.1567(a)(3)]

- j. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods referenced in §63.1566(b) and §63.1567(b). [§63.1566(b), §63.1567(b)]
- k. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in §63.1566(c) and §63.1567(c). [§63.1566(c), §63.1567(c)]
- l. The permittee shall meet each applicable emission limitation in Table 29 of subpart UUU. If the sulfur recovery unit is subject to the NSPS for sulfur oxides in §60.104 of this chapter, the permittee must meet the emission limitations for NSPS units. [§63.1568(a)(1)]
- m. The permittee shall meet each applicable operating limit in Table 30 of Subpart UUU. [§63.1568(a)(2)]
- n. The permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures of the plan. [§63.1568(a)(3), §63.1569(a)(3)]
- o. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods referenced in §63.1568(b). [§63.1568(b)]
- p. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in §63.1568(c). [§63.1568(c)]
- q. For each bypass line, the permittee shall select and comply with one of the options given in §63.1569(a)(1) and meet applicable work practice standards given in Table 36 of Subpart UUU. [§63.1569(a)(1)]
- r. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods listed in §63.1569(b). [§63.1569(b)]
- s. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in §63.1569(c). [§63.1569(c)]
- t. The permittee shall comply with all of the non-opacity standards in Subpart UUU during the times specified in §63.6(f)(1). [§63.1570(a)]
- u. The permittee shall comply with the opacity and visible emission limits of Subpart UUU during the times specified in §63.6(h)(1). [§63.1570(b)]
- v. The permittee shall always operate and maintain affected sources, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i). During the period between the compliance date specified and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, the permittee must maintain a log detailing the operation and maintenance of the process and emissions control equipment. [§63.1570(c)]

- w. The permittee must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3). [§63.1570(d)]
- x. During periods of startup, shutdown, and malfunction, the permittee shall operate in accordance with the SSMP. [§63.1570(e)]
- y. The permittee shall report each instance in which it did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. The permittee also must report each instance in which it did not meet the work practice standards in this subpart that apply. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.1575. [§63.1570(f)]
- z. Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the permittee demonstrates to the Administrator's satisfaction that it was operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e) and the contents of the SSMP. [§63.1570(g)]
- aa. The permittee shall comply with the applicable portions of §63.1571 – Performance Tests and Initial Compliance Demonstration. [§63.1571]
- bb. As applicable, the permittee shall install, operate, and maintain each continuous emission monitoring system according to the following: [§63.1572(a)]
 - i. The permittee must install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of Subpart UUU.
 - ii. If the permittee uses a continuous emission monitoring system to meet the NSPS CO or SO₂ limit, you must conduct a performance evaluation of each continuous emission monitoring system according to the requirements in §63.8 and Table 40 of Subpart UUU. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.
 - iii. As specified in §63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
 - iv. Data must be reduced as specified in §63.8(g)(2).
- cc. As applicable, the permittee shall install, operate, and maintain each continuous parameter monitoring system according to the following: [§63.1572(c)]

- dd. The permittee shall install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately. The permittee shall also meet the equipment specifications in Table 41 of Subpart UUU if pH strips or colormetric tube sampling systems are used.
- ee. The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. The permittee must have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).
- ff. Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.
- gg. Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day. The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.
- hh. Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.
- ii. The permittee shall monitor and collect data according to the following: [§63.1572(d)]
 - i. Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.
 - ii. The permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities for purposes of Subpart UUU, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. The permittee must use all the data collected during all other periods in assessing the operation of the control device and associated control system.
- jj. The permittee shall identify any specifically applicable requirements related to the monitoring alternatives as necessary. [§63.1573]
- kk. The permittee shall comply with the applicable notification requirements, reporting requirements, and record keeping requirements. [§63.1574, §63.1575, §63.1576]
- ll. The permittee shall identify applicable requirements pertaining to Subpart UUU as the information becomes available. The latest updates to applicable requirements shall be submitted to ADEQ along with future application materials. The information will be

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used to update this permit condition to more specifically list applicable requirements.
[19.304 of Regulation]

13. This facility is subject to the federal regulations identified herein at the time of permit issuance. The source(s) affected by these regulations must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in this permit or its appendices. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit. [§19.304 of Regulation 19 and 40 CFR Part 52 Subpart E]

Title VI Provisions

14. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]
- a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
 - b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
 - c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
 - d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.
15. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]
- a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
 - b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
 - c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
 - d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC-like appliance" as defined at §82.152.)

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- e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
 - f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.
16. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.
17. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.
- a. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant.
18. The permittee can switch from any ozone-depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G, "Significant New Alternatives Policy Program".

Permit Shield

19. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in Table 7 - Applicable Regulations of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated June 10, 2005.

Table 47 - Permit Shield Applicable Regulations

SN	Regulation	Description
Facility	Ark. Pollution Control and Ecology Commission Regulation 19	Compilation of Regulation of the Arkansas State Implementation Plan for Air Pollution Control
Facility	Ark. Pollution Control and Ecology Commission Regulation 26	Regulations of the Arkansas Operating Air Permit Program
SN-850, SN-862	40 CFR Part 60, Subpart Dc	Standards of Performance for Small Industrial-Commercial Steam Generating Units

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SN	Regulation	Description
SN-803, SN-804, SN-805, SN-805N, SN-806, SN-808, SN-809, SN-810, SN-811, SN-812, SN-813a, SN-814, SN-821 (a,b,c), SN-822, SN-823, SN-824, SN-825, SN-828, SN-830, SN-832, SN-842, SN-844, SN-850, SN-857, SN-860, SN-861, SN-862	40 CFR Part 60, Subpart J	Standards of Performance for Petroleum Refineries
T-532, T-108, T-109, T-188	40 CFR Part 60 Subpart Ka	Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification commenced after May 18, 1978 and prior to July 23, 1984
T-7, T-88, T-103, T-24, T-113, T-272, T-273, T-274, T-382 through T-387, T-544, T-548, T-553, T-19, T-59, T-247, T-372, T-998	40 CFR Part 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Storage Vessels) for which Construction, Reconstruction, or Modification commenced after July 23, 1984
T-382, T-383, T-24, T-41, T-78, T-112, T-382 through T-387, T-New	40 CFR Part 60, Subpart UU	Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture
Equipment Leaks*	40 CFR Part 60 Subpart VV	Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry
#4 Crude Unit, #6 Hydrotreater/Isomerization Unit, #12 Distillate Hydrotreater, #17 Sulfur Recovery Plant*, and #19 PMA Plant	40 CFR Part 60, Subpart GGG	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
Facility	40 CFR Part 61 Subpart FF	National Emission Standard for Benzene Waste Operations

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SN	Regulation	Description
Facility*, T-36, T-61, T-62, T-64, T-65, T-66, T-67, T-85, T-89, T-120, T-123, T-124, T-125, T-126, T-128, T-245, T-246, T-360, T-361, T-371, T-532, T-536, T-998	40 CFR Part 63, Subpart CC	National Emission Standard for Hazardous Air Pollutants from Petroleum Refineries
SN-824, SN-824A	40 CFR Part 63, Subpart LLLLL	National Emission Standard for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing
*Equipment leak provisions apply only to those components that are subject to Subpart GGG (incorporating the provisions of Subpart VV) and 40 C.F.R. 63, Subpart CC.		

The permit specifically identifies the following as inapplicable based upon information submitted by the permittee in an application dated June 10, 2005.

Table 48 - Permit Shield Inapplicable Regulations

Description of Regulation	Regulatory Citation	Affected Source	Basis for Determination
Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	40 C.F.R. 60 Subpart Dc	SN-828	Units were installed before 1989.
Standards of Performance for Petroleum Refineries	40 C.F.R. 60, Subpart J	SN-809, SN-810	Constructed prior to the effective dates of Subpart J.
Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.	40 C.F.R. 60, Subpart Ka	T-610, T-108, T-109, T-142, T-143, and T-432	Smaller than 40,000 gallons. Exempt from controls because these tanks store a petroleum liquid with a maximum true vapor pressure less than 10.3 kPa (1.5 psia).
Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.	40 C.F.R. 60, Subpart Kb	T-24, T-113, T-272 to T-274, T-382-387, T-553, T-544, and T-548, T-553	Exempt because they store a liquid with a maximum true vapor pressure less than 5.2 kPa (.75 psia).

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Description of Regulation	Regulatory Citation	Affected Source	Basis for Determination
		T-324	Exempt because capacity greater than or equal to 75 m ³ , but less than 151 m ³ storing a liquid with a maximum true vapor pressure less than 15.0 kPa (4.0 psia).
		T-538, T-539, T-540, T-549 to T-552, T-600 to T-609, T-611, and T-612	Smaller than 40 m ³ .
---	40 C.F.R. 60, Subpart K, Ka, and Kb	All tanks not previously identified	Constructed prior to June 11, 1973; Constructed prior to May 19, 1978; Constructed prior to July 23, 1984 (as applicable); or do not exceed size requirements for the subparts.
Standards of Performance for Asphalt Roofing Manufacture	40 C.F.R. 60, Subpart UU	Blowing Stills (associated with SN-825)	Constructed prior to November 18, 1980.
National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene	40 C.F.R. 61, Subpart J	Pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges and other connectors, product accumulator vessels, and control devices or systems	There are no affected facilities in benzene service (greater than 10% benzene by weight).
National Emission Standard for Benzene Emissions From Benzene Storage Vessels	40 C.F.R. 61, Subpart Y	Storage Vessels	None of the storage vessels contain benzene products.

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Description of Regulation	Regulatory Citation	Affected Source	Basis for Determination
National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	40 C.F.R. 63, Subpart Q	Cooling Tower	Cooling towers have not operated with chromium-based water treatment chemicals on or after September 8, 1994.

Consent Decree (CIV. No. 03-1028) Requirements

The following conditions are required to be added to this permit by Paragraph 24 of the Consent Decree (CIV. No. 03-1028) reached between Lion Oil, the US EPA, and ADEQ. In many instances, these conditions are restatements of requirements which appear elsewhere in the Specific and/or Plantwide Conditions of this permit.

20. The following heaters and boilers should be identified as affected facilities and subject to and required to comply with all applicable requirements of the New Source Performance Standards, Subparts A and J: #6 Hydrotreater/Reboiler (SN-806), #9 Stabilizer Reboiler (SN-812), #11 Deasphalting Furnace (SN-814), #16 Asphalt Blowing Furnaces (SN-825), Asphalt Rack Steam Heater (SN-828), Asphalt Hot Regenerate Furnace (SN-830), and the Asphalt Hot Oil Heater (SN-850). Provided however that if there is a future revision of NSPS Subpart J which excludes either certain fuel gas combustion devices or fuel gas streams from NSPS Subpart J, then that exemption, as applicable, shall apply to the foregoing heaters and boilers. [§19.304 of Regulation 19 and 40 CFR Part 60 Subparts A and J]
21. The permittee shall not burn fuel oil in any combustion unit except under the following circumstances. [§19.304 of Regulation 19 and 40 CFR §60.11(d)]
 - a. The permittee shall be permitted to burn torch oil in the FCCU regenerator during FCCU start-ups;
 - b. Lion Oil shall be permitted to burn Fuel Oil in combustion units after the establishment of FCCU NO_x emission limits pursuant to Paragraph 11.E. of this Consent Decree, provided that emissions from any such combustion units are routed through the FCCU Wet Gas Scrubber and Lion Oil demonstrates, with the approval of EPA, that the NO_x emission limits established therein and the SO₂ emissions limits set forth in Paragraph 12.B. of this Consent Decree will continue to be met.
 - c. During periods of natural gas curtailment where the permittee shall burn only LPG or low sulfur distillate (e.g. No. 2 oil at less than 0.5% sulfur by wt.).
22. The Sulfur Recovery Plant (SN-844) is subject to and required to comply with all applicable provisions of 40 CFR Part 60 (NSPS) Subparts A and J. [§19.304 of Regulation 19 and 40 CFR Part 60 Subparts A and J]
23. The permittee shall route all sulfur pit emissions from the sulfur recovery plant (SN-844) such that sulfur pit emissions to the atmosphere are either eliminated or are included and monitored as part of the applicable sulfur recovery plant tail gas emissions that meet the NSPS Subpart J limit

for SO₂: a 12-hour rolling average of 250 ppmvd SO₂ corrected to 0% oxygen. [§19.304 of Regulation 19 and 40 CFR §60.104(a)(2)]

24. The permittee shall comply with the Preventive Maintenance and Operation Plan for the Sulfur Recovery Plant, including any modifications thereto, at all times, including periods of start up, shut down, and malfunction. [§19.304 of Regulation 19 and 40 CFR §60.11(d)]
25. The High and Low Pressure Flares (SN-822 and SN-823) are subject to and shall comply with all applicable requirements of 40 CFR Part 60 Subparts A and J. The following conditions apply to facility compliance with the Subpart J. [§19.304 of Regulation 19 and 40 CFR Part 60 Subparts A and J]
 - a. For continuous or intermittent, routinely-generated refinery fuel gases that are combusted in the high or low pressure flare (SN-822 or SN-823), the permittee shall either take the flare that is associated with such a gas stream out of service, or comply with the emission limit of 40 CFR §60.104(a)(1).
 - b. The combustion of gases generated by the start-up, shut-down, or malfunction of a refinery process unit or released to a flaring device as a result of relief valve leakage or other emergency malfunction are exempt from the requirement to comply with 40 CFR §60.104(a)(1).
 - c. The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d) to minimize HC and AG flaring incidents (as defined below).
 - d. The permittee shall ensure that all continuous or intermittent, routinely-generated refinery fuel gases that are combusted in any flaring device are monitored by a CEM system as required by 40 CFR §60.105(a)(4) or with a parametric monitoring system approved by EPA as an alternative monitoring system under 40 CFR §60.13(i). The permittee shall comply with the reporting requirements of 40 CFR Part 60 Subpart J for all such flaring devices.
26. These definitions shall apply to the following requirements.
 - a. **AG Flaring Incident** shall mean the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas which results in the emission of sulfur dioxide equal to, or in excess of, 500 pounds in any 24-hour period in excess of the permitted limit; provided, however, that if 500 pounds or more of sulfur dioxide have been emitted in a 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour periods, each period which results in emissions equal to, or in excess of 500 pounds of sulfur dioxide in excess of the permitted limit, then only one AG flaring incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of flaring within the AG flaring incident.
 - b. **Tail Gas Incident** shall mean the combustion of tail gas that either is: (i.) combusted in a flare and results in 500 pounds or more of SO₂ emissions in any 24-hour period, or (ii.) combusted in a thermal incinerator and results in excess emissions of 500 pounds or more

of SO₂ emissions in any 24-hour period. Only those time periods which are in excess of an SO₂ concentration of 250 ppm (rolling 12-hour average) shall be used to determine the amount of excess SO₂ emissions from the incinerator. Lion Oil shall use engineering judgment and/or other monitoring data during periods in which the SO₂ CEM system has exceeded the range of the instrument or is out of service.

- c. **Hydrocarbon (HC) Flaring Incident** shall mean continuous or intermittent hydrocarbon flaring, except for acid gas or sour water stripper gas, or tail gas, at a hydrocarbon flaring device that results in the emission of sulfur dioxide equal to or greater than 500 pounds in a 24-hour period; provided, however, that if 500 pounds or more of SO₂ have been emitted in a 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour periods, each period of which results in emissions equal to or in excess of 500 pounds of SO₂, then only one HC flaring incident shall have occurred. Subsequent contiguous, non-overlapping periods are measured from the initial commencement of flaring within the HC flaring incident.
27. The permittee shall comply with the following requirements as they relate to AG flaring incidents, tail gas incidents, and HC flaring incidents. [§19.304 of Regulation 19 and 40 CFR §60.11(d)]
- a. For tail gas incidents, the investigative and corrective action procedures shall be applied to TGU shutdowns, bypasses of a TGU, unscheduled shutdowns of a sulfur recovery plant, or other miscellaneous unscheduled sulfur recovery plant events which result in a tail gas incident.
 - b. The permittee shall investigate the root cause and all contributing causes of all AG flaring incidents, tail gas incidents, and HC flaring incidents. The permittee shall take reasonable steps to correct the conditions that have caused or contributed to such incidents, and to minimize such incidents. The permittee shall evaluate whether AG flaring incidents, tail gas incidents, and HC flaring incidents are due to malfunctions.
 - c. In response to any AG flaring incident, tail gas incident, or HC flaring incident, the permittee shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all contributing causes of the AG flaring incident, tail gas incident, or HC flaring incident.
28. The permittee is prohibited from using the emissions reductions that result from the installation and operation of the controls required by the Consent Decree (CIV. No. 03-1028) ("CD Emissions Reductions") for the purpose of emissions netting or emissions offsets, while still allowing the permittee to use a fraction of the CD emissions reductions if: (1) the emission unit for which the permittee seeks to use the CD emissions reductions are modified or constructed for the purposes of compliance with Tier II gasoline or low-sulfur diesel requirements; and (2) the emissions from those modified or newly-constructed units are below the levels outlined in paragraph 27.C.ii of the Consent Decree (CIV. No. 03-1028) prior to the commencement of operations of the emissions units for which the permittee seeks to use the CD emissions reductions.

- a. **General Prohibition** – The permittee shall not generate or use any NO_x, SO₂, PM, VOC, or CO emissions reductions that result from any projects conducted or controls required pursuant to the Consent Decree (CIV. No. 03-1028) as netting reductions or emissions offsets in any PSD, major non-attainment, and/or minor New Source Review (NSR) permit or permit proceeding.
- b. **Exception to General Prohibition:**
 - i. Utilization of the exception set forth in paragraph 27.C.ii of the Consent Decree (CIV. No. 03-1028) to the general prohibition against the generation or utilization of CD emissions reductions set forth in paragraph 27.B of the Consent Decree (CIV. No. 03-1028) is subject to the following conditions:
 - 1. Under no circumstances shall the permittee use CD emissions reductions for netting and/or offsets prior to the time that actual CD emissions reductions have occurred.
 - 2. CD emissions reductions may only be used at the El Dorado refinery that generated them.
 - 3. The CD emissions reductions provisions of the Consent Decree (CIV. No. 03-1028) are for the purposes of the Consent Decree (CIV. No. 03-1028) only and neither the permittee nor any other entity may use CD emissions reductions for any purpose, including in any subsequent permitting or enforcement proceeding, except as provided herein.
 - 4. The permittee shall remain subject to all federal and state regulations applicable to the PSD, major non-attainment, and/or minor NSR permitting processes.
 - ii. Notwithstanding the general prohibition set forth in Paragraph 27.B of the Consent Decree (CIV. No. 03-1028), the permittee may use 10 tons per year of NO_x, 10 tpy of PM, and 35 tpy of SO₂ from the CD emissions reductions as credits or offsets in any PSD, major non-attainment, and/or minor NSR permit or permit proceeding occurring after the date of lodging of the Consent Decree (CIV. No. 03-1028) (March 11, 2003), provided that the new or modified emissions unit: (1) is being constructed or modified for the purposes of compliance with Tier II gasoline or low-sulfur diesel requirements; and (2) has a federally enforceable permit that reflects:
 - 1. For heaters and boilers, that next-generation ultra low-NO_x burners are installed and the limit is established pursuant to Paragraph 16.D of the Consent Decree (CIV. No. 03-1028).
 - 2. For heaters and boilers, a limit of 0.10 grains of hydrogen sulfide per dry standard cubic foot (dscf) of fuel gas or 20 ppmvd SO₂ corrected to 0% oxygen both on a 3-hour rolling average.

3. For heaters and boilers, no liquid or solid fuel firing authorization.
 4. For the FCCU, a limit of 20 ppmvd NO_x or less corrected to 0% oxygen on a 365-day rolling average basis.
 5. For the FCCU, a limit of 25 ppmvd SO₂ corrected to 0% oxygen on a 365-day rolling average basis.
 6. For SRP's, NSPS Subpart J emission limits.
29. None of the conditions of this permit are intended to prohibit the permittee from seeking to: (1) utilize or generate emissions credits or reductions from refinery units that are covered by the Consent Decree (CIV. No. 03-1028) to the extent that the proposed credits or reductions represent the difference between the emissions limitations set forth in the Consent Decree (CIV. No. 03-1028) for these refinery units and the more stringent emissions limitations that the permittee may elect to accept for those refinery units in a permitting process; or (2) utilize or generate or generate emission credits or reductions on refinery units that are not covered by the Consent Decree (CIV. No. 03-1028).
30. By no later than December 31, 2004, Lion Oil shall install a VDU overhead recovery system on the Vacuum Distillation Tower pursuant to the terms and conditions in its October 9, 2002 submission to the Agencies. Lion has complied with this requirement by routing emissions to the Flare Gas Recovery system.

Additional Requirements

31. The permittee must prepare and implement a Startup, Shutdown, and Malfunction Plan (SSM). If the Department requests a review of the SSM, the permittee will make the SSM available for review. The permittee must keep a copy of the SSM at the source's location and retain all previous versions of the SSM plan for five years. [Regulation No. 19 §19.304 and 40 CFR 63.6(e)(3)]
32. By no later than June 30, 2003, Lion Oil shall, for the El Dorado SRP, submit to EPA and ADEQ, a summary of a plan, implemented or to be implemented, for enhanced maintenance and operation of the El Dorado SRP, any supplemental control devices, and the appropriate Upstream Process Units. This plan shall be termed a Preventive Maintenance and Operation Plan ("PMO Plan"). The PMO Plan shall be a compilation of Lion Oil's approaches for exercising good air pollution control practices for minimizing SO₂ emissions at the El Dorado Refinery. The PMO Plan shall provide for continuous operation of the El Dorado SRP between scheduled maintenance turnarounds with minimization of emissions from the El Dorado SRP. The PMO Plan shall include, but not be limited to, sulfur shedding procedures, new startup and shutdown procedures, emergency procedures and schedules to coordinate maintenance turnarounds of the El Dorado SRP Claus trains and any supplemental control device to coincide with scheduled turnarounds of major Upstream Process Units. The PMO Plan shall have as a goal the elimination of Acid Gas Flaring. Lion Oil shall comply with the PMO Plan at all times, including periods of start up, shut down, and Malfunction of the El Dorado SRP through and after termination of the Consent Decree (CIV. No. 03-1028). Modifications related to minimizing Acid Gas Flaring and/or SO₂ emissions made by Lion Oil to the PMO Plan shall be summarized

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in an annual submission to EPA and the ADEQ until termination of the Consent Decree (CIV. No. 03-1028). [Paragraph 18(D)(i) of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA]

Section VI: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement is a significant activity even if this activity meets the criteria of §304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated July 20, 2007.

Table 49- Insignificant Activities

Description	Category
Fire suppression systems, emissions from fire or emergency response equipment and training, including but not limited to, use of fire control equipment and pumps powered by internal combustion engines, equipment testing, and training.	A-13
Repair of electrical generators.	A-13
Equipment used for surface coating, painting, dipping, or spraying operations that do not emit any VOC or HAP.	A-9
Up to 93 storage tanks each of which is less than or equal to 250 gallons and stores a liquid having a true vapor pressure less than or equal to 3.5 psia (24.2 kPa).	A-2
Up to 34 fuel additive and treatment chemical storage tanks each of which is less than or equal to 10,000 gallons and stores a liquid having a true vapor pressure less than or equal to 0.5 psia (3.5 kPa).	A-3
Caustic storage tanks that contain no VOCs.	A-4
Operation of the OCC Emergency Use Generator (with a maximum capacity of 100 kW fired with diesel fuel) and other Emergency use portable pumps, generators, compressors and boilers not otherwise specifically listed by name or application in this permit or insignificant activities list, provided that the units are less than 10,000,000 Btu/hr and used for back-up power generation during times when the primary source of power is unavailable to the facility.	A-1

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Description	Category
Operation of Emergency Use fuel-fired compressors in lieu of the East Instrument Air Compressor, West Instrument Air Compressor, East Utility Air Compressor, West Utility Air Compressor, North ESGV Compressor, South ESGV Compressor and the CCR Air Compressor, provided that the operation of the fuel-fired equipment does not operate in conjunction with the facility's primary compressors.	A-12
Operation of Emergency Use, 25kW natural gas-fired generator (IT Generator)	A-1
Asphalt Protective Coatings Baghouse (former SN-807)	A-13
Acid Fume Scrubbers (former SN-826 and SN-827)	A-13
Lime Silo Baghouse (former SN-845)	A-13

Pursuant to §26.304 of Regulation 26, the Department determined the emission units, operations, or activities contained in Regulation 19, Appendix A, Group B, to be insignificant activities. Activities included in this list are allowable under this permit and need not be specifically identified.

Section VII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation No. 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute.[40 CFR 70.6(b)(2)]
2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26), effective August 10, 2000]
3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation No. 26 §26.406]
4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.* (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation No. 26 §26.701(A)(2)]
5. The permittee must maintain the following records of monitoring information as required by this permit. [40 CFR 70.6(a)(3)(ii)(A) and Regulation No. 26 §26.701(C)(2)]
 - a. The date, place as defined in this permit, and time of sampling or measurements;
 - b. The date(s) analyses performed;
 - c. The company or entity performing the analyses;
 - d. The analytical techniques or methods used;
 - e. The results of such analyses; and
 - f. The operating conditions existing at the time of sampling or measurement.

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6. The permittee must retain the records of all required monitoring data and support information for at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation No. 26 §26.701(C)(2)(b)]
7. The permittee must submit reports of all required monitoring every 6 months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within 30 days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26 §26.2 must certify all required reports. The permittee will send the reports to the address below: [40 C.F.R. 70.6(a)(3)(iii)(A) and §26.701(C)(3)(a) of Regulation #26]

Arkansas Department of Environmental Quality
Air Division
ATTN: Compliance Inspector Supervisor
Post Office Box 8913
Little Rock, AR 72219

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.
 - a. For all upset conditions (as defined in Regulation 19, §19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:
 - i. The facility name and location
 - ii. The process unit or emission source deviating from the permit limit,
 - iii. The permit limit, including the identification of pollutants, from which deviation occurs,
 - iv. The date and time the deviation started,
 - v. The duration of the deviation,
 - vi. The average emissions during the deviation,
 - vii. The probable cause of such deviations,
 - viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future, and
 - ix. The name of the person submitting the report.

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The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

- b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a. [Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]
9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), §26.701(E) of Regulation No. 26, and A.C.A. §8-4-203, as referenced by §8-4-304 and §8-4-311]
10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation No. 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation No. 26 §26.701(F)(1)]
11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation No. 26 §26.701(F)(2)]
12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation No. 26 §26.701(F)(3)]
13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation No. 26 §26.701(F)(4)]
14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation No. 26 §26.701(F)(5)]

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15. The permittee must pay all permit fees in accordance with the procedures established in Regulation No. 9. [40 CFR 70.6(a)(7) and Regulation No. 26 §26.701(G)]
16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation No. 26 §26.701(H)]
17. If the permit allows different operating scenarios, the permittee will, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation No. 26 §26.701(I)(1)]
18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation No. 26 §26.702(A) and (B)]
19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation No. 26 §26.2. [40 CFR 70.6(c)(1) and Regulation No. 26 §26.703(A)]
20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation No. 26 §26.703(B)]
 - a. Enter upon the permittee's premises where the permitted source is located or emissions-related activity is conducted, or where records must be kept under the conditions of this permit;
 - b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
 - c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
 - d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.
21. The permittee will submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation No. 26 §26.703(E)(3)]
 - a. The identification of each term or condition of the permit that is the basis of the certification;

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- b. The compliance status;
 - c. Whether compliance was continuous or intermittent;
 - d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
 - e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.
22. Nothing in this permit will alter or affect the following: [Regulation No. 26 §26.704(C)]
- a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
 - b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
 - c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act or,
 - d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.
23. This permit authorizes only those pollutant-emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

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Appendix A Subpart Ka – Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978 and Prior to July 23, 1984

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each affected facility equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112.

[45 FR 23379, Apr. 4, 1980]

Subpart Ka—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

§ 60.110a Applicability and designation of affected facility.

(a) *Affected facility.* Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a storage capacity greater than 151,416 liters (40,000 gallons) that is used to store petroleum liquids for which construction is commenced after May 18, 1978.

(b) Each petroleum liquid storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer is not an affected facility and, therefore, is exempt from the requirements of this subpart.

(c) *Alternative means of compliance—(1) Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§ 60.112a through 60.114a for storage vessels that are subject to this subpart that store petroleum liquids that, as stored, have a maximum true vapor pressure equal to or greater than 10.3 kPa (1.5 psia). Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (c)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

[45 FR 23379, Apr. 4, 1980, as amended at 65 FR 78275, Dec. 14, 2000]

§ 60.111a Definitions.

In addition to the terms and their definitions listed in the Act and subpart A of this part the following definitions apply in this subpart:

(a) *Storage vessel* means each tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 204.9 kPa (15 psig) without emissions to the atmosphere except under emergency conditions.

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM D396-78, 89, 90, 92, 96, or 98, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM D2880-78 or 96, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM D2880-78 or 96, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM D975-78, 96, or 98a. (These three methods are incorporated by reference—see § 60.17.)

(c) *Petroleum refinery* means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

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

(e) *Condensate* means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

(f) *True vapor pressure* means the equilibrium partial pressure exerted by a petroleum liquid such as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from External Floating-Roof Tanks, Second Edition, February 1980 (incorporated by reference—see § 60.17).

(g) *Reid vapor pressure* is the absolute vapor pressure of volatile crude oil and nonviscous petroleum liquids, except liquified petroleum gases, as determined by ASTM D323-82 or 94 (incorporated by reference—see § 60.17).

(h) *Liquid-mounted seal* means a foam or liquid-filled primary seal mounted in contact with the liquid between the tank wall and the floating roof continuously around the circumference of the tank.

(i) *Metallic shoe seal* includes but is not limited to a metal sheet held vertically against the tank wall by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(j) *Vapor-mounted seal* means a foam-filled primary seal mounted continuously around the circumference of the tank so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the tank wall, the liquid surface, and the floating roof.

(k) *Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

[45 FR 23379, Apr. 4, 1980, as amended at 48 FR 3737, Jan. 27, 1983; 52 FR 11429, Apr. 8, 1987; 65 FR 61756, Oct. 17, 2000]

§ 60.112a Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

(1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in paragraph (a)(1)(ii)(D) of this section, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(i) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:

(A) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm² per meter of tank diameter (10.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

(B) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).

(C) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.

(D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (a)(1)(ii)(B) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.

(C) There are to be no holes, tears or other openings in the seal or seal fabric.

(D) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

(iii) Each opening in the roof except for automatic bleeder vents and rim

space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in paragraph (a)(1)(iv) of this section. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.

(iv) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(2) A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

(3) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which

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is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114a.

(b) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure greater than 76.6 kPa (11.1 psia), shall equip the storage vessel with a vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

[45 FR 23379, Apr. 4, 1980, as amended at 45 FR 83229, Dec. 18, 1980]

§ 60.113a Testing and procedures.

(a) Except as provided in § 60.8(b) compliance with the standard prescribed in § 60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in § 60.114a.

(1) The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:

(i) Determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequency:

(A) For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

(B) For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.

(C) If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs (a)(1)(i)(A) and (a)(1)(i)(B) of this section.

(D) Keep records of each gap measurement at the plant for a period of at least 2 years following the date of measurement. Each record shall identify the vessel on which the measurement was performed and shall contain the date of the seal gap measurement, the raw data obtained in the measurement process required by paragraph (a)(1)(ii) of this section and the calculation required by paragraph (a)(1)(iii) of this section.

(E) If either the seal gap calculated in accord with paragraph (a)(1)(iii) of this section or the measured maximum seal gap exceeds the limitations specified by § 60.112a of this subpart, a report shall be furnished to the Administrator within 60 days of the date of measurements. The report shall identify the vessel and list each reason why the vessel did not meet the specifications of § 60.112a. The report shall also describe the actions necessary to bring the storage vessel into compliance with the specifications of § 60.112a.

(ii) Determine gap widths in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the tank in each place where a $\frac{1}{8}$ " diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (a)(1)(ii)(B) of this section shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide

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the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in § 60.112a(a)(1)(i) and § 60.112a(a)(1)(ii).

(iv) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.

(2) The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

(i) Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.

(ii) The manufacturer's design specifications and estimated emission reduction capability of the system.

(iii) The operation and maintenance plan for the system.

(iv) Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

[45 FR 23379, Apr. 4, 1980, as amended at 52 FR 11429, Apr. 8, 1987]

§ 60.114a Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112a, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in § 60.112a.

(e) The primary vapor-mounted seal in the "Volume-Maximizing Seal" manufactured by R.F.I. Services Corporation is approved as equivalent to the vapor-mounted seal required by § 60.112a(a)(1)(i) and must meet the gap criteria specified in § 60.112a(a)(1)(i)(B). There shall be no gaps between the tank wall and any secondary seal used in conjunction with the primary seal in the "Volume-Maximizing Seal".

[52 FR 11429, Apr. 8, 1987]

§ 60.115a Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated

true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) The owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112a(a)(3) and (b), or a closed vent system and control device meeting the specifications of 40 CFR 65.42(b)(4), (b)(5), or (c).

[45 FR 23379, Apr. 4, 1980, as amended at 65 FR 78276, Dec. 14, 2000]

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

SOURCE: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§ 60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of § 60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who

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Appendix B Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) The owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112a(a)(3) and (b), or a closed vent system and control device meeting the specifications of 40 CFR 65.42(b)(4), (b)(5), or (c).

[45 FR 23379, Apr. 4, 1980, as amended at 65 FR 78275, Dec. 14, 2000]

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

SOURCE: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§ 60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of § 60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who

choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor

vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see § 60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879-83, 96, or 97 (incorporated by reference—see § 60.17);

(4) Any other method approved by the Administrator.

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

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323-82 or 94 (incorporated by reference—see § 60.17).

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and

shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal

floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in § 60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in § 60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is

being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§ 60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m³ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.8 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in § 60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in § 60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of § 60.112b.

(a) After installing the control equipment required to meet § 60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in § 60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel

with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(i) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet § 60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the

vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between

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the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm² per meter of tank diameter; and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of § 60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in

advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.112b (a)(3) or (b)(2) (other than a flare) is exempt from § 60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by § 60.7(a)(1) or, if the facility is exempt from § 60.7(a)(1), as an attachment to the notification required by § 60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an

explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, § 60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112b, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same

emissions reduction as specified in § 60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of § 60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Keep a record of each inspection performed as required by § 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall

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identify the storage vessel and the reason it did not meet the specifications of § 60.112b(a)(1) or § 60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with § 60.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), furnish the Administrator with a report that contains:

- (i) The date of measurement.
- (ii) The raw data obtained in the measurement.
- (iii) The calculations described in § 60.113b(b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

- (i) The date of measurement.
- (ii) The raw data obtained in the measurement.
- (iii) The calculations described in § 60.113b(b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with § 60.112b(a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

- (1) A copy of the operating plan.
- (2) A record of the measured values of the parameters monitored in accordance with § 60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with § 60.112b,

the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by § 60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in § 60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within

30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17); or

(ii) ASTM D323-82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of §60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

§60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 18, 1987]

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.90 dscm (31.8 dscf).

(2) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

[54 FR 6667, Feb. 14, 1989]

Subpart J—Standards of Performance for Petroleum Refineries

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

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this subpart except as provided under paragraphs (c) and (d) of this section.

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

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

(e) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the

fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[43 FR 10863, Mar. 15, 1978, as amended at 44 FR 61543, Oct. 25, 1979; 54 FR 34026, Aug. 17, 1989]

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) *Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

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

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

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

(e) *Process upset gas* means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

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

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

(h) *Coke burn-off* means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

(i) *Claus sulfur recovery plant* means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) *Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) *Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) *Reduced sulfur compounds* means hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).

(m) *Fluid catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

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

(o) *Fresh feed* means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

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

(q) *Valid day* means a 24-hour period in which at least 18 valid hours of data are obtained. A "valid hour" is one in which at least 2 valid data points are obtained.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10868, Mar. 15, 1978; 44 FR 13481, Mar. 12, 1979; 45 FR 79453, Dec. 1, 1980; 54 FR 34027, Aug. 17, 1989]

§ 60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate

matter emissions shall not exceed 43.0 g/MJ (0.10 lb/million Btu) of heat input attributable to such liquid or solid fossil fuel.

[39 FR 9815, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10868, Feb. 15, 1978; 54 FR 34027, Aug. 17, 1989; 65 FR 61753, Oct. 17, 2000]

§ 60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis).

[54 FR 34027, Aug. 17, 1989, as amended at 55 FR 40175, Oct. 2, 1990]

§ 60.104 Standards for sulfur oxides.

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

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO₂) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H₂S), each calculated as ppm SO₂ by volume (dry basis) at zero percent excess air.

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

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

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

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in § 60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

[43 FR 10869, Mar. 15, 1978, as amended at 54 FR 34027, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000]

§ 60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fluid catalytic cracking unit catalyst regenerators subject to § 60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

(2) For fluid catalytic cracking unit catalyst regenerators subject to § 60.103(a), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2) (ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of Appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in § 10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere (except where an H₂S monitor is installed under paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO₂ and 25 percent oxygen (O₂).

(ii) The SO₂ monitoring level equivalent to the H₂S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the S₂ emissions into the atmosphere from each of the combustion devices.

(4) In place of the SO₂ monitor in paragraph (a)(3) of this section, an instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H₂S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned.

(iii) The performance evaluations for this H₂S monitor under § 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to § 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm SO₂ and 25 percent O₂.

(ii) The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for

conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to § 60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and O₂ emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO₂ (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 25 percent O₂.

(ii) The performance evaluations for this reduced sulfur (and O₂) monitor under § 60.13(c) shall use Performance Specification 5 of Appendix B of this Part (and Performance Specification 3 of Appendix B of this Part for the O₂ analyzer). Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O₂ concentrations below 0.25 percent during the performance specification test, the O₂ concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O₂ monitor.

(7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or O₂ dilution and oxidation system to convert the reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant SO₂. The monitor shall include an oxygen monitor for correcting the data for excess oxygen.

(i) The span values for this monitor are 375 ppm SO₂ and 25 percent O₂.

(ii) For reporting purposes, the SO₂ exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ (and O₂) monitor under § 60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

(8) An instrument for continuously monitoring and recording concentrations of SO₂ in the gases at both the inlet and outlet of the SO₂ control device from any fluid catalytic cracking unit catalyst regenerator for which the

owner or operator seeks to comply with § 60.104 (b)(1).

(i) The span value of the inlet monitor shall be set 125 percent of the maximum estimated hourly potential SO₂ emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential sulfur dioxide emission concentration entering the control device.

(ii) The performance evaluations for these SO₂ monitors under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(9) An instrument for continuously monitoring and recording concentrations of SO₂ in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 ppmv emission limit under § 60.104 (b)(1).

(i) The span value of the monitor shall be set at 50 percent of the maximum hourly potential SO₂ emission concentration of the control device.

(ii) The performance evaluations for this SO₂ monitor under § 60.13 (c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(10) An instrument for continuously monitoring and recording concentrations of oxygen (O₂) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 ppmv standard) from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with § 60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous

monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the § 60.13(e) performance evaluation.

(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

(13) When seeking to comply with § 60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

(i) The test methods as described in § 60.106(k);

(ii) A spare continuous monitoring system; or

(iii) Other monitoring systems as approved by the Administrator.

(b) [Reserved]

(c) The average coke burn-off rate (Mg (tons) per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102, § 60.103, or § 60.104(b)(2).

(d) For any fluid catalytic cracking unit catalyst regenerator under § 60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

NOTE: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) *Opacity*. All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under § 60.105(a)(1) exceeds 30 percent.

(2) *Carbon monoxide*. All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under § 60.105(a)(2) exceeds 500 ppm.

(3) *Sulfur dioxide from fuel gas combustion*. (i) All rolling 3-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under § 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) *Sulfur dioxide from Claus sulfur recovery plants*. (i) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO₂) as measured by the reduced sulfur continuous monitoring system under § 60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

[39 FR 9315, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975; 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10869, Mar. 15, 1978; 48 FR 23611, May 25, 1983; 50 FR 31701, Aug. 5, 1985; 54 FR 34028, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000]

§ 60.106 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particulate

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matter (PM) standards in § 60.102(a) as follows:

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

$$E = \frac{c_s Q_{sd}}{KR_c}$$

Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.

c_s = Concentration of PM, g/dscm (gr/dscf).

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

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

K = Conversion factor, 1,000 g/kg (7,000 gr/lb).

(2) Method 5B or 5F is to be used to determine particulate matter emissions and associated moisture content from affected facilities without wet FGD systems; only Method 5B is to be used after wet FGD systems. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

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

$$R_c = K_1 Q_e (\%CO_2 + \%CO) - (K_2 Q_a - K_3 Q_r) / ((\%CO/2) + (\%CO_2 + \%O_2))$$

Where:

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

Q_e = Volumetric flow rate of exhaust gas from catalyst regenerator before entering the emission control system, dscm/min (dscf/min).

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

$\%CO_2$ = Carbon dioxide concentration, percent by volume (dry basis).

$\%CO$ = Carbon monoxide concentration, percent by volume (dry basis).

$\%O_2$ = Oxygen concentration, percent by volume (dry basis).

K_1 = Material balance and conversion factor, 2.982×10^{-4} (Mg-min)/(hr-dscm-%) [9.31×10^{-6} (ton-min)/(hr-dscf-%)].

K_2 = Material balance and conversion factor, 2.088×10^{-3} (Mg-min)/(hr-dscm-%) [6.52×10^{-5} (ton-min)/(hr-dscf-%)].

K_3 = Material balance and conversion factor, 9.94×10^{-5} (Mg-min)/(hr-dscm-%) [3.1×10^{-6} (ton-min)/(hr-dscf-%)].

(i) Method 2 shall be used to determine the volumetric flow rate (Q_e).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine CO_2 , CO, and O_2 concentrations.

(4) Method 9 and the procedures of § 60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in § 60.102(b) as follows:

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

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

Where:

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

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

A = Allowable incremental rate of PM emissions, 7.5×10^{-4} kg/million J (0.10 lb/million Btu).

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

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

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate (R_c).

(d) The owner or operator shall determine compliance with the CO standard in § 60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e)(1) The owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train

without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line.

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

(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.

(iii) For Method 15A, a 1-hour sample shall constitute a run.

(2) Where emissions are monitored by § 60.105(a)(3), compliance with § 60.105(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. A 1-hour sample shall constitute a run. Method 6 samples shall be taken at a rate of approximately 2 liters/min. The ppm correction factor (Method 6) and the sampling location in paragraph (f)(1) of this section apply. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C.

(f) The owner or operator shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in § 60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO_2 concentration. The concentration in mg/dscm obtained by Method 6 or 6C is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than $5.00 m^2$ ($53.8 ft^2$) or at a point no closer to the walls than 1.00 m (39.4 in.) if the cross-sectional area is $5.00 m^2$ or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of

these eight samples shall constitute a run. For Method 6C, a run shall consist of the arithmetic average of four 1-hour samples. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 or 3A. The samples shall be taken simultaneously with the SO_2 , reduced sulfur and H_2S , or moisture samples. The SO_2 , reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(6) of this section.

(g) Each performance test conducted for the purpose of determining compliance under § 60.104(b) shall consist of all testing performed over a 7-day period using Method 6 or 6C and Method 3 or 3A. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

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(h) For the purpose of determining compliance with § 60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, ppmv) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in § 60.13(h). These calculations are made using the emission data collected under § 60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$$R_{SO_2} = 100(C_{SO_2}(i) - C_{SO_2}(o))/C_{SO_2}(i)$$

where:

R_{SO_2} = 7-day average sulfur dioxide emission reduction, percent

$C_{SO_2}(i)$ = sulfur dioxide emission concentration determined in § 60.106(h)(2) at the inlet to the add-on control device, ppmv

$C_{SO_2}(o)$ = sulfur dioxide emission concentration determined in § 60.106(h)(2) at the outlet to the add-on control device, ppmv

100 = conversion factor, decimal to percent

(4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 ppmv standard, reported on a dry, O₂-free basis, shall be calculated using the procedures outlined in § 60.106(h)(1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (h) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$$C_{adj} = C_{meas} [20.9/(20.9 - \%O_2)]$$

where:

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

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

20.9 = 20.9 percent oxygen - 0.0 percent oxygen (defined oxygen correction basis), percent

20.9 = oxygen concentration in air, percent

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

(i) For the purpose of determining compliance with § 60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (i)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in § 60.106(i)(3) for moisture content and for the concentration of sulfur oxides calculated as sulfur dioxide,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160 °C (320 °F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler.

An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel SO_x credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (b)(3) of this section, unless paragraph (i)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8-3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide (C_{sox}).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E_{sox} = C_{sox} Q_{sd} / K$$

Where:

E_{sox} = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr)

C_{sox} = sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm (gr/dscf)

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

K=1,000 g/kg (7,000 gr/lb)

(10) Sulfur oxides emissions calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$R_{sox} = (E_{sox} / R_c)$$

Where:

R_{sox} = Sulfur oxides emissions calculated as kg sulfur dioxide per Mg (lb/ton) coke burn-off.

E_{sox} = Sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr).

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

(11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per Mg (ton) of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with § 60.104(b)(2), as provided in § 60.8(b). Any requests for ap-

proval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(j) For the purpose of determining compliance with § 60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129-64, 78, or 95, ASTM D1552-83 or 95, ASTM D2622-87, 94, or 98, or ASTM D1266-87, 91, or 98. (These methods are incorporated by reference: see § 60.17.) The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (j)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^n \frac{S_i Q_i}{Q_f}$$

where:

S_f = fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

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Q_r = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

S_i = fresh feed sulfur content expressed in percent by weight of fresh feed for the "ith" sampling location.

Q_i = volumetric flow rate of fresh feed stream for the "ith" sampling location.

(4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.

(k) The test methods used to supplement continuous monitoring system data to meet the minimum data requirements in § 60.104(d) will be used as described below or as otherwise approved by the Administrator.

(1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.

(3) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.

(4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10869, Mar. 15, 1978; 51 FR 42842, Nov. 26, 1986; 52 FR 20392, June 1, 1987; 53 FR 41333, Oct. 21, 1988; 54 FR 34028, Aug. 17, 1989; 55 FR 40176, Oct. 2, 1990; 56 FR 4176, Feb. 4, 1991; 65 FR 61754, Oct. 17, 2000]

§ 60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to § 60.104(b) shall notify the Administrator of the specific provisions of § 60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by § 60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of § 60.104(b), then the Administrator shall be notified by

the owner or operator in the report described in paragraph (c) of this section.

(b) Each owner or operator subject to § 60.104(b) shall record and maintain the following information:

(1) If subject to § 60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to § 60.105(a)(13) and § 60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to § 60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if § 60.106(i)(12) applies.

(3) If subject to § 60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to § 60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O₂-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1) is below 90 percent and above 50 vppm, as measured by the continuous monitoring system prescribed under § 60.105(a)(8), or above 50 vppm, as measured by the outlet continuous monitoring system prescribed under § 60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under § 60.106(h);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator

seeks to comply with § 60.104(b)(2) exceeds 9.8 kg SO_x per 1,000 kg coke burn-off, as measured by the daily testing prescribed under § 60.106(i). The average emission rate shall be determined using the procedures specified under § 60.106(i); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with § 60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under § 60.106(j).

(2) Any 30-day period in which the minimum data requirements specified in § 60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:

(i) The date that the exceedance occurred;

(ii) An explanation of the exceedance;

(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and

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

(4) If subject to § 60.104(b)(1),

(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;

(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;

(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;

(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(5) If subject to § 60.104(b)(2), for each day in which a Method 8 sample result

required by § 60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator.

(6) If subject to § 60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by § 60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

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

(f) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

[54 FR 34029, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7465, Feb. 12, 1999; 65 FR 61755, Oct. 17, 2000]

§ 60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in § 60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under § 60.104(b). Performance tests conducted for the purpose of determining compliance under § 60.104(b) shall be conducted according

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to the applicable procedures specified under § 60.106.

(b) Owners or operators who seek to comply with § 60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with § 60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under § 60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to § 60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under § 60.106. In the event that a sample collected under § 60.106(i) or (j) is accidentally lost or conditions occur in which one of the samples must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to § 60.104(b) who has demonstrated compliance with one of the provisions of § 60.104(b) but a later date seeks to comply with another of the provisions of § 60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of § 60.104(b). The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by § 60.107(e).

[54 FR 34030, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7466, Feb. 12, 1999]

§ 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

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(b) Authorities which shall not be delegated to States:

- (1) Section 60.105(a)(13)(iii),
- (2) Section 60.108(i)(12).

[54 FR 34031, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990]

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

[42 FR 37937, July 25, 1977, as amended at 45 FR 23379, Apr. 4, 1980]

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Storage vessel* means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

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Appendix C Subpart J – Standards of Performance for Petroleum Refineries

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

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(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.90 dscm (31.8 dscf).

(2) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

[54 FR 6667, Feb. 14, 1989]

Subpart J—Standards of Performance for Petroleum Refineries

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

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this subpart except as provided under paragraphs (c) and (d) of this section.

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

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

(e) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the

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fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[43 FR 10868, Mar. 15, 1978, as amended at 44 FR 61543, Oct. 25, 1979; 54 FR 34026, Aug. 17, 1989]

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) *Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

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

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

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

(e) *Process upset gas* means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

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

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

(h) *Coke burn-off* means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

(i) *Claus sulfur recovery plant* means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) *Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) *Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) *Reduced sulfur compounds* means hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).

(m) *Fluid catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

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

(o) *Fresh feed* means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

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

(q) *Valid day* means a 24-hour period in which at least 18 valid hours of data are obtained. A "valid hour" is one in which at least 2 valid data points are obtained.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10868, Mar. 15, 1978; 44 FR 13481, Mar. 12, 1979; 45 FR 79453, Dec. 1, 1980; 54 FR 34027, Aug. 17, 1989]

§ 60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate

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matter emissions shall not exceed 43.0 g/MJ (0.10 lb/million Btu) of heat input attributable to such liquid or solid fossil fuel.

[39 FR 9315, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10868, Feb. 15, 1978; 54 FR 34027, Aug. 17, 1989; 65 FR 61753, Oct. 17, 2000]

§ 60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis).

[54 FR 34027, Aug. 17, 1989, as amended at 55 FR 40175, Oct. 2, 1990]

§ 60.104 Standards for sulfur oxides.

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

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO₂) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H₂S), each calculated as ppm SO₂ by volume (dry basis) at zero percent excess air.

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

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

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

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in § 60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

[43 FR 10869, Mar. 15, 1978, as amended at 54 FR 34027, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000]

§ 60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fluid catalytic cracking unit catalyst regenerators subject to § 60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

(2) For fluid catalytic cracking unit catalyst regenerators subject to § 60.103(a), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2) (ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of Appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in § 10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere (except where an H₂S monitor is installed under paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO₂ and 25 percent oxygen (O₂).

(ii) The SO₂ monitoring level equivalent to the H₂S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the S₂ emissions into the atmosphere from each of the combustion devices.

(4) In place of the SO₂ monitor in paragraph (a)(3) of this section, an instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H₂S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned.

(iii) The performance evaluations for this H₂S monitor under § 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to § 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm SO₂ and 25 percent O₂.

(ii) The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for

conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to § 60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and O₂ emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO₂ (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 25 percent O₂.

(ii) The performance evaluations for this reduced sulfur (and O₂) monitor under § 60.13(c) shall use Performance Specification 5 of Appendix B of this Part (and Performance Specification 3 of Appendix B of this Part for the O₂ analyzer). Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O₂ concentrations below 0.25 percent during the performance specification test, the O₂ concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O₂ monitor.

(7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or O₂ dilution and oxidation system to convert the reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant SO₂. The monitor shall include an oxygen monitor for correcting the data for excess oxygen.

(i) The span values for this monitor are 375 ppm SO₂ and 25 percent O₂.

(ii) For reporting purposes, the SO₂ exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ (and O₂) monitor under § 60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

(8) An instrument for continuously monitoring and recording concentrations of SO₂ in the gases at both the inlet and outlet of the SO₂ control device from any fluid catalytic cracking unit catalyst regenerator for which the

owner or operator seeks to comply with § 60.104 (b)(1).

(i) The span value of the inlet monitor shall be set 125 percent of the maximum estimated hourly potential SO₂ emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential sulfur dioxide emission concentration entering the control device.

(ii) The performance evaluations for these SO₂ monitors under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(9) An instrument for continuously monitoring and recording concentrations of SO₂ in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 ppmv emission limit under § 60.104 (b)(1).

(i) The span value of the monitor shall be set at 50 percent of the maximum hourly potential SO₂ emission concentration of the control device.

(ii) The performance evaluations for this SO₂ monitor under § 60.13 (c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(10) An instrument for continuously monitoring and recording concentrations of oxygen (O₂) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 ppmv standard) from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with § 60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous

monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the § 60.13(e) performance evaluation.

(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

(13) When seeking to comply with § 60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

(i) The test methods as described in § 60.106(k);

(ii) A spare continuous monitoring system; or

(iii) Other monitoring systems as approved by the Administrator.

(b) [Reserved]

(c) The average coke burn-off rate (Mg (tons) per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102, § 60.103, or § 60.104(b)(2).

(d) For any fluid catalytic cracking unit catalyst regenerator under § 60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

NOTE: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) *Opacity*. All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under § 60.105(a)(1) exceeds 30 percent.

(2) *Carbon monoxide*. All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under § 60.105(a)(2) exceeds 500 ppm.

(3) *Sulfur dioxide from fuel gas combustion*. (i) All rolling 3-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under § 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) *Sulfur dioxide from Claus sulfur recovery plants*. (i) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO₂) as measured by the reduced sulfur continuous monitoring system under § 60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

[39 FR 9315, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975; 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10869, Mar. 15, 1978; 48 FR 23611, May 25, 1983; 50 FR 31701, Aug. 5, 1985; 54 FR 34028, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000]

§ 60.106 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particulate

matter (PM) standards in § 60.102(a) as follows:

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

$$E = \frac{c_s Q_{sd}}{KR_c}$$

Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.

c_s = Concentration of PM, g/dscm (gr/dscf).

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

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

K = Conversion factor, 1,000 g/kg (7,000 gr/lb).

(2) Method 5B or 5F is to be used to determine particulate matter emissions and associated moisture content from affected facilities without wet FGD systems; only Method 5B is to be used after wet FGD systems. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

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

$$R_c = K_1 Q_e (\%CO_2 + \%CO) - (K_2 Q_a - K_3 Q_r) / ((\%CO/2) + (\%CO_2 + \%O_2))$$

Where:

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

Q_e = Volumetric flow rate of exhaust gas from catalyst regenerator before entering the emission control system, dscm/min (dscf/min).

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

$\%CO_2$ = Carbon dioxide concentration, percent by volume (dry basis).

$\%CO$ = Carbon monoxide concentration, percent by volume (dry basis).

$\%O_2$ = Oxygen concentration, percent by volume (dry basis).

K_1 = Material balance and conversion factor, 2.982×10^{-4} (Mg-min)/(hr-dscm-%) [9.31×10^{-6} (ton-min)/(hr-dscf-%)].

K_2 = Material balance and conversion factor, 2.088×10^{-3} (Mg-min)/(hr-dscm-%) [6.52×10^{-5} (ton-min)/(hr-dscf-%)].

K_3 = Material balance and conversion factor, 9.94×10^{-5} (Mg-min)/(hr-dscm-%) [3.1×10^{-6} (ton-min)/(hr-dscf-%)].

(i) Method 2 shall be used to determine the volumetric flow rate (Q_r).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine CO_2 , CO, and O_2 concentrations.

(4) Method 9 and the procedures of § 60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in § 60.102(b) as follows:

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

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

Where:

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

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

A = Allowable incremental rate of PM emissions, 7.5×10^{-4} kg/million J (0.10 lb/million Btu).

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

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

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate (R_c).

(d) The owner or operator shall determine compliance with the CO standard in § 60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e)(1) The owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train

without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line.

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

(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.

(iii) For Method 15A, a 1-hour sample shall constitute a run.

(2) Where emissions are monitored by §60.105(a)(3), compliance with §60.105(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. A 1-hour sample shall constitute a run. Method 6 samples shall be taken at a rate of approximately 2 liters/min. The ppm correction factor (Method 6) and the sampling location in paragraph (f)(1) of this section apply. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C.

(f) The owner or operator shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in §60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO_2 concentration. The concentration in mg/dscm obtained by Method 6 or 6C is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than $5.00 m^2$ ($53.8 ft^2$) or at a point no closer to the walls than 1.00 m (39.4 in.) if the cross-sectional area is $5.00 m^2$ or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of

these eight samples shall constitute a run. For Method 6C, a run shall consist of the arithmetic average of four 1-hour samples. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 or 3A. The samples shall be taken simultaneously with the SO_2 , reduced sulfur and H_2S , or moisture samples. The SO_2 , reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(6) of this section.

(g) Each performance test conducted for the purpose of determining compliance under §60.104(b) shall consist of all testing performed over a 7-day period using Method 6 or 6C and Method 3 or 3A. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

(h) For the purpose of determining compliance with § 60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, ppmv) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in § 60.13(h). These calculations are made using the emission data collected under § 60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$$R_{SO_2} = 100(C_{SO_2(i)} - C_{SO_2(o)}) / C_{SO_2(i)}$$

where:

R_{SO_2} = 7-day average sulfur dioxide emission reduction, percent

$C_{SO_2(i)}$ = sulfur dioxide emission concentration determined in § 60.106(h)(2) at the inlet to the add-on control device, ppmv

$C_{SO_2(o)}$ = sulfur dioxide emission concentration determined in § 60.106(h)(2) at the outlet to the add-on control device, ppmv

100 = conversion factor, decimal to percent

(4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 ppmv standard, reported on a dry, O₂-free basis, shall be calculated using the procedures outlined in § 60.106(h)(1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (h) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$$C_{adj} = C_{meas} [20.9 / (20.9 - \%O_2)]$$

where:

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

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

20.9 = 20.9 percent oxygen - 0.0 percent oxygen (defined oxygen correction basis), percent

20.9 = oxygen concentration in air, percent

%O₂ = oxygen concentration measured on a dry basis, percent

(i) For the purpose of determining compliance with § 60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (i)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in § 60.106(i)(3) for moisture content and for the concentration of sulfur oxides calculated as sulfur dioxide,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160 °C (320 °F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler.

An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel SO_x credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (b)(3) of this section, unless paragraph (i)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8-3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide (C_{sox}).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E_{sox} = C_{sox} Q_{sd}/K$$

Where:

E_{sox} = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr)

C_{sox} = sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm (gr/dscf)

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

K = 1,000 g/kg (7,000 gr/lb)

(10) Sulfur oxides emissions calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$R_{sox} = (E_{sox}/R_c)$$

Where:

R_{sox} = Sulfur oxides emissions calculated as kg sulfur dioxide per Mg (lb/ton) coke burn-off.

E_{sox} = Sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr).

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

(11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per Mg (ton) of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with § 60.104(b)(2), as provided in § 60.8(b). Any requests for ap-

proval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(j) For the purpose of determining compliance with § 60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129-64, 78, or 95, ASTM D1552-83 or 95, ASTM D2622-87, 94, or 98, or ASTM D1266-87, 91, or 98. (These methods are incorporated by reference: see § 60.17.) The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (j)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^n \frac{S_i Q_i}{Q_f}$$

where:

S_f = fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

Q_r = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

S_i = fresh feed sulfur content expressed in percent by weight of fresh feed for the "ith" sampling location.

Q_i = volumetric flow rate of fresh feed stream for the "ith" sampling location.

(4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.

(k) The test methods used to supplement continuous monitoring system data to meet the minimum data requirements in § 60.104(d) will be used as described below or as otherwise approved by the Administrator.

(1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.

(3) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.

(4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10869, Mar. 15, 1978; 51 FR 42842, Nov. 26, 1986; 52 FR 20392, June 1, 1987; 53 FR 41333, Oct. 21, 1988; 54 FR 34028, Aug. 17, 1989; 55 FR 40176, Oct. 2, 1990; 56 FR 4176, Feb. 4, 1991; 65 FR 61754, Oct. 17, 2000]

§ 60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to § 60.104(b) shall notify the Administrator of the specific provisions of § 60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by § 60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of § 60.104(b), then the Administrator shall be notified by

the owner or operator in the report described in paragraph (c) of this section.

(b) Each owner or operator subject to § 60.104(b) shall record and maintain the following information:

(1) If subject to § 60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to § 60.105(a)(13) and § 60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to § 60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if § 60.106(i)(12) applies.

(3) If subject to § 60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to § 60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O₂-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1) is below 90 percent and above 50 vppm, as measured by the continuous monitoring system prescribed under § 60.105(a)(8), or above 50 vppm, as measured by the outlet continuous monitoring system prescribed under § 60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under § 60.106(h);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator

seeks to comply with § 60.104(b)(2) exceeds 9.8 kg SO_x per 1,000 kg coke burn-off, as measured by the daily testing prescribed under § 60.106(i). The average emission rate shall be determined using the procedures specified under § 60.106(i); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with § 60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under § 60.106(j).

(2) Any 30-day period in which the minimum data requirements specified in § 60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:

(i) The date that the exceedance occurred;

(ii) An explanation of the exceedance;

(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and

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

(4) If subject to § 60.104(b)(1),

(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;

(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;

(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;

(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(5) If subject to § 60.104(b)(2), for each day in which a Method 8 sample result

required by § 60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator.

(6) If subject to § 60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by § 60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

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

(f) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

[54 FR 34029, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7465, Feb. 12, 1999; 65 FR 61755, Oct. 17, 2000]

§ 60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in § 60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under § 60.104(b). Performance tests conducted for the purpose of determining compliance under § 60.104(b) shall be conducted according

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to the applicable procedures specified under § 60.106.

(b) Owners or operators who seek to comply with § 60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with § 60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under § 60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to § 60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under § 60.106. In the event that a sample collected under § 60.106(i) or (j) is accidentally lost or conditions occur in which one of the samples must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to § 60.104(b) who has demonstrated compliance with one of the provisions of § 60.104(b) but a later date seeks to comply with another of the provisions of § 60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of § 60.104(b). The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by § 60.107(e).

[54 FR 34030, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7466, Feb. 12, 1999]

§ 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

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(b) Authorities which shall not be delegated to States:

- (1) Section 60.105(a)(13)(iii),
- (2) Section 60.106(i)(12).

[54 FR 34031, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990]

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

[42 FR 37937, July 25, 1977, as amended at 45 FR 23379, Apr. 4, 1980]

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Storage vessel* means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Appendix D Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

following the end of the reporting period.

(x) Facility-specific nitrogen oxides standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the nitrogen oxides emission limit is 215 ng/J (0.5 lb/million Btu).

(2) *Emission monitoring for nitrogen oxides.* (i) The nitrogen oxides emissions shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in § 60.46b.

(ii) The monitoring of the nitrogen oxides emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 60 FR 28062, May 30, 1995; 61 FR 14031, Mar. 29, 1996; 62 FR 52641, Oct. 8, 1997; 63 FR 49455, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999; 65 FR 13243, Mar. 13, 2000; 69 FR 40773, July 7, 2004]

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 55 FR 37683, Sept. 12, 1990, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not covered by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not covered by this subpart.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 71 FR 9884, Feb. 27, 2006]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient com-

bustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see § 60.17).

Dry flue gas desulfurization technology means a sulfur dioxide (SO₂) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference—see § 60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth

of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but

are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO₂.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000; 71 FR 9884, Feb. 27, 2006]

§ 60.42c Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: Cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent SO₂ reduction requirement specified in this paragraph and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20

percent (0.20) of the potential SO₂ emission rate (80 percent reduction), nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 90 percent SO₂ reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO₂ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 50 percent (0.50) of the potential SO₂ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 260 ng/J (0.60 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO₂ reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 million Btu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a Federally enforceable requirement limiting

operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the following:

(1) The percent of potential SO₂ emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel,

(ii) Has a heat input capacity greater than 22 MW (75 million Btu/hr), and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = (K_a H_a + K_b H_b + K_c H_c) / (H_a + H_b + H_c)$$

where:

E_s is the SO₂ emission limit, expressed in ng/J or lb/million Btu heat input.

K_a is 520 ng/J (1.2 lb/million Btu),

K_b is 260 ng/J (0.60 lb/million Btu),

K_c is 215 ng/J (0.50 lb/million Btu),

H_a is the heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [million Btu]

H_b is the heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (million Btu)

H_c is the heat input from the combustion of oil, in J (million Btu).

(f) Reduction in the potential SO₂ emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO₂ emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO₂ control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f)(1), (2), or (3), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 million Btu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(i) The SO₂ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at

all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000; 71 FR 9884, Feb. 27, 2006]

§60.43c Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/million Btu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in

excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On or after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2) and (e)(3) of this section. Affected facilities subject to this paragraph, are also subject to the requirements of paragraphs (c) and (d) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification

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commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000; 71 FR 9835, Feb. 27, 2006]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and in § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of

the steam generating unit. Compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) and § 60.8, compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c is based on the average percent reduction and the average SO₂ emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO₂ emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average SO₂ emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{hoO}) is used in Equation 19-19 of Method 19 to compute the adjusted E_{ao} (E_{aoO}). The E_{hoO} is computed using the following formula:

$$E_{hoO} = [E_{ho} - E_w(1 - X_k)]/X_k$$

where:

E_{hoO} is the adjusted E_{ho} , ng/J (lb/million Btu)

E_{ho} is the hourly SO₂ emission rate, ng/J (lb/million Btu)

E_w is the SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9, ng/J (lb/million Btu). The value E_w for each fuel

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lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w=0$.

X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) [where percent reduction is not required] does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100(1 - \%R_p/100)(1 - \%R_r/100)$$

where

$\%P_s$ is the percent of potential SO_2 emission rate, in percent

$\%R_p$ is the SO_2 removal efficiency of the control device as determined by Method 19, in percent

$\%R_r$ is the SO_2 removal efficiency of fuel pretreatment as determined by Method 19, in percent

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_p$ ($\%R_{pO}$) is computed from E_{soO} from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{soO}) using the following formula:

$$\%R_{pO} = 100 [1.0 - E_{soO}/E_{soO}]$$

where:

$\%R_{pO}$ is the adjusted $\%R_p$, in percent

E_{soO} is the adjusted E_{so} , ng/J (lb/million Btu)

E_{soO} is the adjusted average SO_2 inlet rate, ng/J (lb/million Btu)

(ii) To compute E_{soO} , an adjusted hourly SO_2 inlet rate (E_{soO}) is used. The E_{soO} is computed using the following formula:

$$E_{soO} = [E_{so} - E_w(1 - X_k)]/X_k$$

where:

E_{soO} is the adjusted E_{so} , ng/J (lb/million Btu)

E_{so} is the hourly SO_2 inlet rate, ng/J (lb/million Btu)

E_w is the SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.45c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under § 60.48c(f)(1), (2), or (3), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated

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24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO₂ emissions data in calculating %P, and E_{pm} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %P, or E_{pm} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) and (d) of this section.

(1) Method 1 shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3 shall be used for gas analysis when applying Method 5, Method 5B, or Method 17.

(3) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of PM as follows:

(i) Method 5 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B may

be used in Method 17 only if Method 17 is used in conjunction with a wet scrubber system. Method 17 shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or Method 5B, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320 ±25 °F).

(6) For determination of PM emissions, an oxygen or carbon dioxide measurement shall be obtained simultaneously with each run of Method 5, Method 5B, or Method 17 by traversing the duct at the same sampling location.

(7) For each run using Method 5, Method 5B, or Method 17, the emission rates expressed in ng/J (lb/million Btu) heat input shall be determined using:

(i) The oxygen or carbon dioxide measurements and PM measurements obtained under this section,

(ii) The dry basis F-factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (appendix A).

(8) Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected

facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) Units that burn only oil containing no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall install, calibrate, maintain, and operate a continuous emission monitoring system and shall comply with the requirements specified in paragraphs (d)(1) through (d)(13) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial start-up of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the continuous monitoring system if the owner or operator was previously determining compliance by Method 5, 5B, or 17 performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for particulate matter emissions as required under §60.8 of subpart A of this part. Compliance with the particulate matter emission

limit shall be determined by using the continuous emission monitoring system specified in paragraph (d) of this section to measure particulate matter and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19, section 4.1.

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

(7) At a minimum, valid continuous monitoring system hourly averages shall be obtained as specified in paragraph (d)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (d)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid continuous emission monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (d)(7) of this section are not met.

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraph (d)(7)(i) of this section.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA reference Method 3, 3A, or 3B, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000; 71 FR 9885, Feb. 27, 2006]

§60.46c Emission monitoring for sulfur dioxide

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO₂ emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO₂ control device (or the outlet of the steam generating unit if no SO₂ control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO₂ concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO₂ control device.

(b) The 1-hour average SO₂ emission rates measured by a CEMS shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO₂ emission rate must be based on at least 30 minutes of operation and include at least 2 data

points representing two 15-minute periods. Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO₂ CEMS at the inlet to the SO₂ control device shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted, and the span value of the SO₂ CEMS at the outlet from the SO₂ control device shall be 50 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO₂ CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by using Method 6B. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method

6B shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according to Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B may be used in lieu of CEMS to measure SO₂ at the inlet or outlet of the SO₂ control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable SO₂ and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 (appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3 or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate

sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, as described under § 60.48c(f) (1), (2), or (3), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, oil, gas, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system, except as specified in paragraphs (c) and (d) of this section.

(b) All COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (appendix B). The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Units that burn only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input

or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.45c(d). The continuous monitoring systems specified in paragraph § 60.45c(d) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000; 71 FR 9886, Feb. 27, 2006]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The

affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂ emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B.

(c) The owner or operator of each coal-fired, residual oil-fired, or wood-fired affected facility subject to the opacity limits under § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility which occur during the reporting period.

(d) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.43c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO₂ emission rate (nj/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO₂ emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO₂ or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent

of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 (appendix B).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), or (3) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier; and

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, spe-

cifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.

(h) The owner or operator of each affected facility subject to a Federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

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(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000; 71 FR 9886, Feb. 27, 2006]

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(c) Any facility covered by subpart Cb, Eb, AAAAA, or BBBBB of this part is not covered by this subpart.

(d) Any facility covered by an EPA approved State section 111(d)/129 plan implementing subpart Cb or BBBBB of this part is not covered by this subpart.

(e) Any facility covered by subpart FFF or JJJ of part 62 of this title (Federal section 111(d)/129 plan implementing subpart Cb or BBBBB of this part) is not covered by this subpart.

[42 FR 37936, July 25, 1977, as amended at 71 FR 27335, May 10, 2006]

§ 60.51 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Incinerator* means any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste by removing combustible matter.

(b) *Solid waste* means refuse, more than 50 percent of which is municipal

type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

(c) *Day* means 24 hours.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 20792, June 14, 1974]

§ 60.52 Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO₂.

[39 FR 20792, June 14, 1974, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.53 Monitoring of operations.

(a) The owner or operator of any incinerator subject to the provisions of this part shall record the daily charging rates and hours of operation.

§ 60.54 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter standard in § 60.52 as follows:

(1) The concentration (C₁₂) of particulate matter, corrected to 12 percent CO₂, shall be computed for each run using the following equation:

$$C_{12} = C_s (12/\%CO_2)$$

where:

C₁₂=concentration of particulate matter, corrected to 12 percent CO₂, g/dscm (gr/dscf).

C_s=concentration of particulate matter, g/dscm (gr/dscf).

%CO₂=CO₂ concentration, percent dry basis.

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Appendix E Subpart FF – National Emission Standards for Benzene Operations

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

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for a source that has an initial startup date after the effective date.

(1) Periods of operation where there were exceedances of monitored parameters recorded under §61.305(b).

(2) All periods recorded under §61.305(c)(1) when the vent stream is diverted from the control device.

(3) All periods recorded under §61.305(d) when the steam generating unit or process heater was not operating.

(4) All periods recorded under §61.305(e) in which the pilot flame of the flare was absent.

(5) All times recorded under §61.305(c)(2) when maintenance is performed on car-sealed valves, when the car seal is broken, and when the valve position is changed.

(g) The owner or operator of an affected facility shall keep the vapor-tightness documentation required under §61.302 (d) and (e) on file at the affected facility in a permanent form available for inspection.

(h) The owner or operator of an affected facility shall update the documentation file required under §61.302 (d) and (e) for each tank truck, railcar, or marine vessel at least once per year to reflect current test results as determined by the appropriate method. The owner or operator shall include, as a minimum, the following information in this documentation:

- (1) Test title;
- (2) Tank truck, railcar, or marine vessel owner and address;
- (3) Tank truck, railcar, or marine vessel identification number;
- (4) Testing location;
- (5) Date of test;
- (6) Tester name and signature;
- (7) Witnessing inspector: name, signature, and affiliation; and
- (8) Test results, including, for railcars and tank trucks, the initial pressure up to which the tank was pressured at the start of the test.

(i) Each owner or operator of an affected facility complying with §61.300(b) or §61.300(d) shall record the following information. The first year after promulgation the owner or operator shall submit a report containing the requested information to the Director of the Emission Standards Division, (MD-13), U.S. Environmental Protec-

tion Agency, Research Triangle Park, North Carolina 27711. After the first year, the owner or operator shall continue to record; however, no reporting is required. The information shall be made available if requested. The information shall include, as a minimum:

(1) The affected facility's name and address;

(2) The weight percent of the benzene loaded;

(3) The type of vessel loaded (i.e., tank truck, railcar, or marine vessel); and

(4) The annual amount of benzene loaded into each type of vessel.

[55 FR 8341, Mar. 7, 1990, as amended at 65 FR 62159, Oct. 17, 2000]

§61.306 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: No restrictions.

Subparts CC-EE [Reserved]

Subpart FF—National Emission Standard for Benzene Waste Operations

SOURCE: 55 FR 8346, Mar. 7, 1990, unless otherwise noted.

§61.340 Applicability.

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from any facility listed in paragraph (a) of

this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

(d) At each facility identified in paragraph (a) or (b) of this section, any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, as defined in §61.341, is exempt from this subpart. No testing, monitoring, recordkeeping, or reporting is required under this subpart for any gaseous stream from a waste management unit, treatment process, or wastewater treatment unit routed to a fuel gas system.

[55 FR 6346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§61.341 Definitions.

Benzene concentration means the fraction by weight of benzene in a waste as determined in accordance with the procedures specified in §61.355 of this subpart.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Chemical manufacturing plant means any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals. Examples of chemical manufacturing plants include facilities at which process units are operated to produce one or more of the following chemicals: benzenesulfonic acid, benzene, chlorobenzene, cumene,

cyclohexane, ethylene, ethylbenzene, hydroquinone, linear alkylbenzene, nitrobenzene, resorcinol, sulfolane, or styrene.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission source to a control device.

Coke by-product recovery plant means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

Container means any portable waste management unit in which a material is stored, transported, treated, or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Cover means a device or system which is placed on or over a waste placed in a waste management unit so that the entire waste surface area is enclosed and sealed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed and sealed when not in use. Example of covers include a fixed roof installed on a tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

External floating roof means a pontoon-type or double-deck type cover with certain rim sealing mechanisms that rests on the liquid surface in a waste management unit with no fixed roof.

Facility means all process units and product tanks that generate waste within a stationary source, and all waste management units that are used for waste treatment, storage, or disposal within a stationary source.

Fixed roof means a cover that is mounted on a waste management unit in a stationary manner and that does

not move with fluctuations in liquid level.

Floating roof means a cover with certain rim sealing mechanisms consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and unit wall.

Flow indicator means a device which indicates whether gas flow is present in a line or vent system.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by facility operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside the facility. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric.

Individual drain system means the system used to convey waste from a process unit, product storage tank, or waste management unit to a waste management unit. The term includes all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving waste management unit.

Internal floating roof means a cover that rests or floats on the liquid surface inside a waste management unit that has a fixed roof.

Liquid-mounted seal means a foam or liquid-filled primary seal mounted in contact with the liquid between the waste management unit wall and the floating roof continuously around the circumference.

Loading means the introduction of waste into a waste management unit but not necessarily to complete capacity (also referred to as filling).

Maximum organic vapor pressure means the equilibrium partial pressure exerted by the waste at the temperature equal to the highest calendar-month average of the waste storage temperature for waste stored above or below the ambient temperature or at

the local maximum monthly average temperature as reported by the National Weather Service for waste stored at the ambient temperature, as determined:

- (1) In accordance with §60.17(c); or
- (2) As obtained from standard reference texts; or
- (3) In accordance with §60.17(a)(37); or
- (4) Any other method approved by the Administrator.

No detectable emissions means less than 500 parts per million by volume (ppmv) above background levels, as measured by a detection instrument reading in accordance with the procedures specified in §61.355(h) of this subpart.

Oil-water separator means a waste management unit, generally a tank or surface impoundment, used to separate oil from water. An oil-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water separator include an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

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

Point of waste generation means the location where the waste stream exits the process unit component or storage tank prior to handling or treatment in an operation that is not an integral part of the production process, or in the case of waste management units that generate new wastes after treatment, the location where the waste stream exits the waste management unit component.

Process unit means equipment assembled and connected by pipes or ducts to

produce intermediate or final products. A process unit can be operated independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Process unit turnaround means the shutting down of the operations of a process unit, the purging of the contents of the process unit, the maintenance or repair work, followed by re-starting of the process.

Process unit turnaround waste means a waste that is generated as a result of a process unit turnaround.

Process wastewater means water which comes in contact with benzene during manufacturing or processing operations conducted within a process unit. Process wastewater is not organic wastes, process fluids, product tank drawdown, cooling tower blowdown, steam trap condensate, or landfill leachate.

Process wastewater stream means a waste stream that contains only process wastewater.

Product tank means a stationary unit that is designed to contain an accumulation of materials that are fed to or produced by a process unit, and is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Product tank drawdown means any material or mixture of materials discharged from a product tank for the purpose of removing water or other contaminants from the product tank.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open

only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, ignitable, explosive, reactive, or hazardous materials.

Segregated stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting rainfall runoff at a facility, and which is segregated from all other individual drain systems.

Sewer line means a lateral, trunk line, branch line, or other enclosed conduit used to convey waste to a downstream waste management unit.

Slop oil means the floating oil and solids that accumulate on the surface of an oil-water separator.

Sour water stream means a stream that:

(1) Contains ammonia or sulfur compounds (usually hydrogen sulfide) at concentrations of 10 ppm by weight or more;

(2) Is generated from separation of water from a feed stock, intermediate, or product that contained ammonia or sulfur compounds; and

(3) Requires treatment to remove the ammonia or sulfur compounds.

Sour water stripper means a unit that:

(1) Is designed and operated to remove ammonia or sulfur compounds (usually hydrogen sulfide) from sour water streams;

(2) Has the sour water streams transferred to the stripper through hard piping or other enclosed system; and

(3) Is operated in such a manner that the offgases are sent to a sulfur recovery unit, processing unit, incinerator, flare, or other combustion device.

Surface impoundment means a waste management unit which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids, and which is

not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

Tank means a stationary waste management unit that is designed to contain an accumulation of waste and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Treatment process means a stream stripping unit, thin-film evaporation unit, waste incinerator, or any other process used to comply with § 61.348 of this subpart.

Vapor-mounted seal means a foam-filled primary seal mounted continuously around the perimeter of a waste management unit so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the unit wall, the liquid surface, and the floating roof.

Waste means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

Waste management unit means a piece of equipment, structure, or transport mechanism used in handling, storage, treatment, or disposal of waste. Examples of a waste management unit include a tank, surface impoundment, container, oil-water separator, individual drain system, steam stripping unit, thin-film evaporation unit, waste incinerator, and landfill.

Waste stream means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, benzene concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate.

Wastewater treatment system means any component, piece of equipment, or installation that receives, manages, or treats process wastewater, product

tank drawdown, or landfill leachate prior to direct or indirect discharge in accordance with the National Pollutant Discharge Elimination System permit regulations under 40 CFR part 122. These systems typically include individual drain systems, oil-water separators, air flotation units, equalization tanks, and biological treatment units.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§ 61.342 Standards: General.

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in §61.355(c)(1)(i) (A) through (C).

(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under §61.11, or by the initial startup for a new source with an initial startup after the effective date.

(1) The owner or operator of an existing source unable to comply with the rule within the required time may request a waiver of compliance under §61.10.

(2) As part of the waiver application, the owner or operator shall submit to the Administrator a plan under §61.10(b)(3) that is an enforceable commitment to obtain environmental ben-

efits to mitigate the benzene emissions that result from extending the compliance date. The plan shall include the following information:

(i) A description of the method of compliance, including the control approach, schedule for installing controls, and quantity of the benzene emissions that result from extending the compliance date;

(ii) If the control approach involves a compliance strategy designed to obtain integrated compliance with multiple regulatory requirements, a description of the other regulations involved and their effective dates; and

(iii) A description of the actions to be taken at the facility to obtain mitigating environmental benefits, including how the benefits will be obtained, the schedule for these actions, and an estimate of the quantifiable benefits that directly result from these actions.

(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:

(1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:

(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in §61.348 of this subpart.

(ii) Comply with the standards specified in §§61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.

(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or

product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.

(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in § 61.355(c)(2) or § 61.355(c)(3).

(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or

(ii) All of the following conditions are met:

(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,

(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in § 61.355(j), and

(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turn-around waste, is determined for the year in which the waste is generated.

(d) As an alternative to the requirements specified in paragraphs (c) and (e) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste other than process wastewater in accordance with the requirements of paragraph (c)(1) of this section.

(2) The owner or operator shall manage and treat process wastewater in accordance with the following requirements:

(i) Process wastewater shall be treated to achieve a total annual benzene quantity from facility process wastewater less than 1 Mg/yr (1.1 ton/yr). Total annual benzene from facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each untreated process wastewater stream plus the annual benzene quantity exiting the treatment process for each process wastewater stream treated in accordance with the requirements of paragraph (c)(1)(i) of this section.

(ii) Each treated process wastewater stream identified in paragraph (d)(2)(i) of this section shall be managed and treated in accordance with paragraph (c)(1) of this section.

(iii) Each untreated process wastewater stream identified in paragraph (d)(2)(i) of this section is exempt from the requirements of paragraph (c)(1) of this section.

(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and

(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turn-around waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

(i) The benzene quantity for the wastes described in paragraph (e)(2) of

this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in §61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in §61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with §61.355(k).

(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:

(1) Comply with the standards specified in §§61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.

(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.

(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in §61.355 of this subpart.

(h) Permission to use an alternative means of compliance to meet the requirements of §§61.342 through 61.352 of this subpart may be granted by the Administrator as provided in §61.353 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 65 FR 62159, 62160, Oct. 17, 2000]

§61.343 Standards: Tanks.

(a) Except as provided in paragraph (b) of this section and in §61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance

with §61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart.

(2) The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with

the requirements specified in paragraph (e) of this section.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 m³ (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 m³ (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(d) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

(e) Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The tank must be located inside a total enclosure. The enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of material into or out of the enclosure by conveyor, vehicles, or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of Procedure T initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the requirements for Tank Level 2 control requirements 40 CFR 264.1084(i) or 40 CFR 265(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(2) The enclosure must be vented through a closed-vent system to a control device that is designed and operated in accordance with the standards for control devices specified in §61.349.

(3) Safety devices, as defined in this subpart, may be installed and operated as necessary on any enclosure, closed-vent system, or control device used to comply with the requirements of paragraphs (e)(1) and (2) of this section.

(4) The closed-vent system must be designed and operated in accordance with the requirements of §61.349.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 18331, May 2, 1990; 58 FR 3096, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 6082, Feb. 6, 2003; 68 FR 67935, Dec. 4, 2003]

§61.344 Standards: Surface impoundments.

(a) The owner or operator shall meet the following standards for each surface impoundment in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each surface impoundment a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the surface impoundment except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the enclosure of the surface impoundment is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods

specified in §61.355(h) of this subpart; and

(3) The pressure is monitored continuously to ensure that the pressure in the enclosure of the surface impoundment remains below atmospheric pressure.

(D) The cover shall be used at all times that waste is placed in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228. (Note: the treatment residuals generated by these activities may be subject to the requirements of this part.)

(ii) The closed-vent system and control device shall be designed and operated in accordance with §61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993]

§61.345 Standards: Containers.

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(3) Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section.

(i) The owner or operator must either:

(A) Vent the container inside a total enclosure which is exhausted through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(A) and (B) of this section; or

(B) Vent the covered or closed container directly through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(B) and (C) of this section.

(ii) The owner or operator must meet the following requirements, as applicable to the type of air emission control equipment selected by the owner or operator:

(A) The total enclosure must be designed and operated in accordance with

the criteria for a permanent total enclosure as specified in section 5 of the "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of containers through the enclosure by conveyor or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the Container Level 3 control requirements in 40 CFR 264.1086(e)(2)(i) or 40 CFR 265.1086(e)(2)(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(B) The closed-vent system and control device must be designed and operated in accordance with the requirements of § 61.349.

(C) For a container cover, the cover and all openings (e.g., doors, hatches) must be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h).

(iii) Safety devices, as defined in this subpart, may be installed and operated as necessary on any container, enclosure, closed-vent system, or control device used to comply with the requirements of paragraph (a)(3)(i) of this section.

(4) If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by methods specified in §61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the container remains below atmospheric pressure.

(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 67936, Dec. 4, 2003]

§61.346 Standards: Individual drain systems.

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste

sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with §61.349 of this subpart.

(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(3) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:

(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(i) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:

(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.

(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with § 61.349 of this subpart.

(3) Each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:

(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.

(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.

(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.

(5) Except as provided in § 61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as

soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3097, Jan. 7, 1993]

§ 61.347 Standards: Oil-water separators.

(a) Except as provided in § 61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure

in the oil-water separator remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3098, Jan. 7, 1993]

§61.348 Standards: Treatment processes.

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:

(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:

(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

(ii) Removes benzene from the waste stream by 99 percent or more on a mass basis, or

(iii) Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.

(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with §61.343 of this subpart.

(3) For the purpose of complying with the requirements specified in para-

graph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.

(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to §61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

(b) Except for facilities complying with §61.342(e), the owner or operator that aggregates or mixes individual waste streams as defined in paragraph (a)(5) of this section for management and treatment in a wastewater treatment system shall comply with the following requirements:

(1) The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in §§61.343 through 61.347 of this subpart.

(2) The provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:

(i) The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in §61.355(c) of this subpart; and

(ii) The total annual benzene quantity contained in all waste streams

managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:

(A) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management unit. The benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.

(B) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.

(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:

(1) Engineering calculations in accordance with requirements specified in §61.356(e) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in §61.355 of this subpart.

(d) A treatment process or waste stream is in compliance with the requirements of this subpart and exempt from the requirements of paragraph (c) of this section provided that the owner or operator documents that the treatment process or waste stream is in

compliance with other regulatory requirements as follows:

(1) The treatment process is a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;

(2) The treatment process is an industrial furnace or boiler burning hazardous waste for energy recovery for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart D;

(3) The waste stream is treated by a means or to a level that meets benzene-specific treatment standards in accordance with the Land Disposal Restrictions under 40 CFR part 268, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of §61.349 of this subpart;

(4) The waste stream is treated by a means or to a level that meets benzene-specific effluent limitations or performance standards in accordance with the Effluent Guidelines and Standards under 40 CFR parts 401-464, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of §61.349 of this subpart; or

(5) The waste stream is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 122.

(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.

(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

(2) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as

soon as practicable, but not later than 15 calendar days after identification.

(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.

(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in §61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in §61.354 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 87231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§61.349 Standards: Closed-vent systems and control devices.

(a) For each closed-vent system and control device used to comply with standards in accordance with §§61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device

in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

(iii) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(i) An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the following conditions:

(A) Reduce the organic emissions vented to it by 95 weight percent or greater;

(B) Achieve a total organic compound concentration of 20 ppmv (as the sum of the concentrations for individual compounds using Method 18) on a dry basis corrected to 3 percent oxygen; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C (1,400 °F). If a boiler or process heater issued as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iii) A flare shall comply with the requirements of 40 CFR 60.18.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

(1) The critical operating parameters that affect the emission control performance of the device;

(2) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

(3) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified

in paragraphs (a)(2)(iv) (B) and (C) of this section to the Administrator prior to operation of the alternative control device.

(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subject to paragraph (a)(2)(iv) of this section meets the requirements of § 61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not meet the requirements of § 61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.

(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.

(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:

(1) Engineering calculations in accordance with requirements specified in § 61.356(f) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section.

(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in § 61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.

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(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visible defects such as holes in ductwork or piping and loose connections.

(g) Except as provided in § 61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with § 61.354(c) of this subpart.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.350 Standards: Delay of repair.

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.

(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

§ 61.351 Alternative standards for tanks.

(a) As an alternative to the standards for tanks specified in § 61.343 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);

(2) An external floating roof meeting the requirements of 40 CFR 60.112b(a)(2); or

(3) An alternative means of emission limitation as described in 40 CFR 60.114b.

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(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of § 61.343 of this subpart applicable to the same facilities.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990]

§ 61.352 Alternative standards for oil-water separators.

(a) As an alternative to the standards for oil-water separators specified in § 61.347 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A floating roof meeting the requirements in 40 CFR 60.693-2(a); or

(2) An alternative means of emission limitation as described in 40 CFR 60.694.

(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§ 61.347 and 61.349 of this subpart shall be installed and operated.

(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in § 61.347 of this subpart applicable to the same facilities.

§ 61.353 Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in benzene emissions at least equivalent to the reduction in benzene emissions from the source achieved by the applicable design, equipment, work practice, or operational requirements in §§ 61.342 through 61.349, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only

after public notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993]

§ 61.354 Monitoring of operations.

(a) Except for a treatment process or waste stream complying with § 61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:

(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with § 61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.

(b) If an owner or operator complies with the requirements of § 61.348(b), then the owner or operator shall monitor each wastewater treatment system to ensure the unit is properly operated and maintained by the appropriate monitoring procedure as follows:

(1) For the first exempt waste management unit in each waste treatment train, other than an enhanced biodegradation unit, measure the flow rate, using the procedures of § 61.355(b), and the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) For each enhanced biodegradation unit that is the first exempt waste management unit in a treatment train, measure the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(c) An owner or operator subject to the requirements in § 61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.

(1) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$ or ± 0.5 $^{\circ}\text{C}$, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$ or ± 0.5 $^{\circ}\text{C}$, whichever is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder.

(4) For a boiler or process heater having a design heat input capacity less than 44 MW (150×10^6 BTU/hr), a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$.

or ± 0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(5) For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150×10^6 BTU/hr), a monitoring device equipped with a continuous recorder to measure a parameter(s) that indicates good combustion operating practices are being used.

(6) For a condenser, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the condenser; or

(ii) A temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ± 1 percent of the temperature being monitored in °C or ± 0.5 °C, whichever is greater. One temperature sensor shall be installed at a location in the exhaust stream from the condenser, and a second temperature sensor shall be installed at a location in the coolant fluid exiting the condenser.

(7) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(ii) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(8) For a vapor recovery system other than a condenser or carbon adsorption system, a monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the control device.

(9) For a control device subject to the requirements of §61.349(a)(2)(iv), devices to monitor the parameters as specified in §61.349(a)(2)(iv)(C).

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(e) An alternative operation or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under §61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by §61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is

maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.355 Test methods, procedures, and compliance provisions.

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in § 61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of § 61.342 (c), (d), or (e).

(4) If the total annual benzene quantity from facility waste is less than 10

Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

(5) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(2) The determination of annual waste quantity for wastes at coke by-product plants subject to and complying with the control requirements of §61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(i) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(ii) The ammonia still meets the definition of a sour water stripper in §61.341.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from off-site shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under §61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good

engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(B) The determination for wastes at coke by-product plants subject to and complying with the control requirements of §61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(7) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is

made through hard piping or other enclosed system.

(2) The ammonia still meets the definition of a sour water stripper in § 61.341.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability

and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at

a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in §61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in §61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in §61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in §61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\bar{C} = \frac{1}{Q_t} \times \sum_{i=1}^n (Q_i)(C_i)$$

Where:

\bar{C} = Flow-weighted annual average benzene concentration for waste stream, ppmw.

Q_t = Total annual waste quantity for waste stream, kg/yr (lb/yr).

n = Number of waste samples (at least 3).

Q_i = Annual waste quantity for waste stream represented by C_i , kg/yr (lb/yr).

C_i = Measured concentration of benzene in waste sample i , ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with §61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with §61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process (E_b) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[\sum_{i=1}^n V_i C_i \right]$$

Where:

E_b = Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m³ (lb/ft³).

V_i = Average volume flow rate of waste entering the treatment process during each run i , m³/hr (ft³/hr).

C_i = Average concentration of benzene in the waste stream entering the treatment process during each run i , ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process (E_a) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6} \left[\sum_{i=1}^n V_i C_i \right]$$

Where:

E_a = Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m³ (lb/ft³).

V_i = Average volume flow rate of waste exiting the treatment process during each run i , m³/hr (ft³/hr).

C_i = Average concentration of benzene in the waste stream exiting the treatment process during each run i , ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(f) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(iii) of this subpart shall determine the benzene destruction efficiency for the combustion unit by the following procedure:

(1) The test shall be conducted under conditions that exist when the combustion unit is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the combustion unit shall be determined by computing the product of the flow rate of the waste stream entering the combustion unit, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling procedures in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene into the combustion unit is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[\sum_{i=1}^n V_i C_i \right]$$

Where:

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

K = Density of the waste stream, kg/m³ (lb/ft³).

V_i = Average volume flow rate of waste entering the combustion unit during each run i , m³/hr (ft³/hr).

C_i = Average concentration of benzene in the waste stream entering the combustion unit during each run i , ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the combustion unit exhaust stack shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected and be the same time period at which the mass flow rate of benzene entering the treatment process is determined. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample and each 1-hour period shall correspond to the periods when the waste feed is sampled.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate.

(C) The average benzene concentration in the exhaust downstream of the combustion unit shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of benzene emitted during each run shall be calculated as follows:

$$M_i = D_b VC(10^{-6})$$

Where:

M_i = Mass of benzene emitted during run i , kg (lb).

V = Volume of air-vapor mixture exhausted at standard conditions, m³ (ft³).

C = Concentration of benzene measured in the exhaust, ppmv.

D_b = Density of benzene, 3.24 kg/m³ (0.202 lb/ft³).

10^6 = Conversion factor for ppmv.

(iv) The benzene mass emission rate in the exhaust shall be calculated as follows:

$$E_a = \left(\sum_{i=1}^n M_i \right) / T$$

Where:

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

M_i = Mass of benzene emitted from the combustion unit during run i , kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(5) The benzene destruction efficiency for the combustion unit shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Benzene destruction efficiency for the combustion unit, percent.

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

(g) An owner or operator using performance tests to demonstrate compliance of a wastewater treatment system unit with §61.348(b) shall measure the flow-weighted annual average benzene concentration of the wastewater stream where the waste stream enters an exempt waste management unit by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the wastewater treatment system is operating at the highest inlet wastewater stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§61.343 through 61.347, and §61.349 of

this subpart in accordance with the following requirements:

(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The background level shall be determined as set forth in Method 21.

(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.

(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under § 61.349(a)(2) shall use the following procedures:

(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.

(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which

at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_1 V_{aj}}{10^6} \left(\sum_{i=1}^n C_{ai} MW_i \right)$$

$$M_{bj} = \frac{K_1 V_{bj}}{10^6} \left(\sum_{i=1}^n C_{bi} MW_i \right)$$

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

V_{aj} = Volume of vent stream entering the control device during run j, at standard conditions, m^3 (ft^3).

V_{bj} = Volume of vent stream exiting the control device during run j, at standard conditions, m^3 (ft^3).

C_{ai} = Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

C_{bi} = Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

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n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then $n=1$.

K_1 = Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))

= 0.0416 kg-mol/m³ (0.00118 lb-mol/ft³)

10^{-6} = Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a = \left(\sum_{j=1}^n M_{aj} \right) / T$$

$$E_b = \left(\sum_{j=1}^n M_{bj} \right) / T$$

Where:

E_a = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_b = Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j , kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j , kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.

E_b = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_a = Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).

(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also

apply to wastes with a water content of 10 percent or less.

(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342(e)(2) by the following procedure:

(1) For each waste stream that is not controlled for air emissions in accordance with § 61.343, 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by § 61.342(e)(2).

(2) For each waste stream that is controlled for air emissions in accordance with § 61.343, 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.

(i) Where the waste stream enters the first waste management unit not complying with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,

(ii) For each waste stream that is managed or treated only in compliance with §§ 61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or

(iii) For wastes managed in units controlled for air emissions in accordance with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and

(k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.

(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and

(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.

(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.

(4) The benzene in waste entering an enhanced biodegradation unit, as defined in § 61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:

(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and

(ii) All prior waste management units managing the waste comply with §§ 61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).

(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.

(6) The total benzene quantity for the purposes of the calculation required by § 61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and

(k)(5) of this section for each applicable waste stream.

(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by § 61.342(e)(2):

(i) Determine which waste management units are involved in the multiple counting of benzene;

(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.

(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by § 61.342(e)(2).

(iv) Submit in the annual report required under § 61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.356 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.

(b) Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, and indicate whether or

not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records:

(1) For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(2) For each waste stream exempt from §61.342(c)(1) in accordance with §61.342(c)(3), the records shall include:

(i) All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with §61.342(c)(3)(i), or

(ii) All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with §61.342(c)(3)(ii).

(3) For each facility where process wastewater streams are controlled for benzene emissions in accordance with §61.342(d) of this subpart, the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

(4) For each facility where waste streams are controlled for benzene emissions in accordance with §61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

(5) For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with §61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with §61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with §61.355(a)(1)(iii) of this section.

(6) For each facility where wastewater streams are controlled for benzene emissions in accordance with §61.348(b)(2), the records shall include all measurements, calculations, and other documentation used to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

(c) An owner or operator transferring waste off-site to another facility for treatment in accordance with §61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment.

(d) An owner or operator using control equipment in accordance with §§61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(e) An owner or operator using a treatment process or wastewater treatment system unit in accordance with §61.348 of this subpart shall maintain the following records. The documentation shall be retained for the life of the unit.

(1) A statement signed and dated by the owner or operator certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.

(2) If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.

(3) If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain all test information necessary to demonstrate the unit performance.

(i) A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc.), and the design flow rate and benzene content.

(ii) Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.

(iii) Records of unit operating conditions during each test run including all key process parameters.

(iv) All test results.

(4) If a control device is used, then the owner or operator shall maintain

the control device records required by paragraph (f) of this section.

(f) An owner or operator using a closed-vent system and control device in accordance with §61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device.

(1) A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur.

(2) If engineering calculations are used to determine control device performance in accordance with §61.349(c), then a design analysis for the control device that includes for example:

(i) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters:

(A) For a thermal vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(C) For a boiler or process heater, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average flame zone temperatures, combustion zone residence time, and description of method and location where the vent stream is introduced into the flame zone.

(D) For a flare, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also consider the requirements specified in 40 CFR 60.18.

(E) For a condenser, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design outlet organic compound concentration level or the design outlet benzene concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(F) For a carbon adsorption system that regenerates the carbon bed directly on-site in the control device such as a fixed-bed adsorber, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, number and capacity of carbon beds, type and working capacity of activated carbon used for carbon beds, design total steam flow over the period of each complete carbon bed regeneration cycle, duration of the carbon bed steaming and cooling/drying cycles, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of carbon.

(G) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of

the control device and source operating schedule.

(H) For a control device subject to the requirements of § 61.349(a)(2)(iv), the design analysis shall consider the vent stream composition, constituent concentration, and flow rate. The design analysis shall also include all of the information submitted under § 61.349 (a)(2)(iv).

(ii) [Reserved]

(3) If performance tests are used to determine control device performance in accordance with § 61.349(c) of this subpart:

(i) A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program.

(ii) A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials.

(iii) A detailed description of sampling and monitoring procedures, including sampling and monitoring locations in the system, the equipment to be used, sampling and monitoring frequency, and planned analytical procedures for sample analysis.

(iv) All test results.

(g) An owner or operator shall maintain a record for each visual inspection required by §§ 61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(h) An owner or operator shall maintain a record for each test of no detectable emissions required by §§ 61.343

through 61.347 and § 61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(i) For each treatment process and wastewater treatment system unit operated to comply with § 61.348, the owner or operator shall maintain documentation that includes the following information regarding the unit operation:

(1) Dates of startup and shutdown of the unit.

(2) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(a)(1) of this subpart, the owner or operator shall maintain records that include date each test is performed and all test results.

(3) If a process parameter is continuously monitored in accordance with § 61.354(a)(2) of this subpart, the owner or operator shall maintain records that include a description of the operating parameter (or parameters) to be monitored to ensure that the unit will be operated in conformance with these standards and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.

(4) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(b), the owner or operator shall maintain records that include the date each test is performed and all test results.

(5) Periods when the unit is not operated as designed.

(j) For each control device, the owner or operator shall maintain documentation that includes the following information

regarding the control device operation:

(1) Dates of startup and shutdown of the closed-vent system and control device.

(2) A description of the operating parameter (or parameters) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device.

(3) Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when:

(i) Any valve car-seal or closure mechanism required under § 61.349(a)(1)(ii) is broken or the by-pass line valve position has changed.

(ii) The flow monitoring devices required under § 61.349(a)(1)(ii) indicate that vapors are not routed to the control device as required.

(4) If a thermal vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature.

(5) If a catalytic vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference.

(6) If a boiler or process heater is used, then the owner or operator shall maintain records of each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone as required by

§61.349(a)(2)(i)(C). For a boiler or process heater having a design heat input capacity less than 44 MW (150×10^6 BTU/hr), the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the boiler or process heater and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature. For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150×10^6 BTU/hr), the owner or operator shall maintain continuous records of the parameter(s) monitored in accordance with the requirements of §61.354(c)(5).

(7) If a flare is used, then the owner or operator shall maintain continuous records of the flare pilot flame monitoring and records of all periods during which the pilot flame is absent.

(8) If a condenser is used, then the owner or operator shall maintain records from the monitoring device of the parameters selected to be monitored in accordance with §61.354(c)(6). If concentration of organics or concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the temperature of the condenser exhaust stream and coolant fluid is monitored, then the owner or operator shall record all 3-hour periods of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(9) If a carbon adsorber is used, then the owner or operator shall maintain records from the monitoring device of the concentration of organics or the concentration of benzene in the control device outlet gas stream. If the concentration of organics or the con-

centration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the carbon bed regeneration interval is monitored, then the owner or operator shall record each occurrence when the vent stream continues to flow through the control device beyond the predetermined carbon bed regeneration time.

(10) If a carbon adsorber that is not regenerated directly on site in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time then the existing carbon in the control device is replaced with fresh carbon.

(11) If an alternative operational or process parameter is monitored for a control device, as allowed in §61.354(e) of this subpart, then the owner or operator shall maintain records of the continuously monitored parameter, including periods when the device is not operated as designed.

(12) If a control device subject to the requirements of §61.349(a)(2)(iv) is used, then the owner or operator shall maintain records of the parameters that are monitored and each occurrence when the parameters monitored are outside the range of values specified in §61.349(a)(2)(iv)(C), or other records as specified by the Administrator.

(k) An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b.

(1) An owner or operator who elects to install and operate the control equipment in §61.352 of this subpart shall maintain records of the following:

(1) The date, location, and corrective action for each visual inspection required by 40 CFR 60.693-2(a)(5), during which a broken seal, gap, or other problem is identified that could result in benzene emissions.

(2) Results of the seal gap measurements required by 40 CFR 60.693-2(a).

(m) If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure.

(n) Each owner or operator using a total enclosure to comply with control requirements for tanks in § 61.343 or the control requirements for containers in § 61.345 must keep the records required in paragraphs (n)(1) and (2) of this section. Owners or operators may use records as required in 40 CFR 264.1089(b)(2)(iv) or 40 CFR 265.1090(b)(2)(iv) for a tank or as required in 40 CFR 264.1089(d)(1) or 40 CFR 265.1090(d)(1) for a container to meet the recordkeeping requirement in paragraph (n)(1) of this section. The owner or operator must make the records of each verification of a total enclosure available for inspection upon request.

(1) Records of the most recent set of calculations and measurements performed to verify that the enclosure meets the criteria of a permanent total enclosure as specified in "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B;

(2) Records required for a closed-vent system and control device according to the requirements in paragraphs (d) (f), and (j) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990; 55 FR 18331, May 2, 1990, as amended at 58 FR 3103, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000; 67 FR 68533, Nov. 12, 2002]

§ 61.357 Reporting requirements.

(a) Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to § 61.342 and is determined by the procedures specified in § 61.355(c) to contain benzene. Each owner or oper-

ator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:

(1) Total annual benzene quantity from facility waste determined in accordance with § 61.355(a) of this subpart.

(2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.

(3) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:

(i) Whether or not the water content of the waste stream is greater than 10 percent;

(ii) Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;

(iii) Annual waste quantity for the waste stream;

(iv) Range of benzene concentrations for the waste stream;

(v) Annual average flow-weighted benzene concentration for the waste stream; and

(vi) Annual benzene quantity for the waste stream.

(4) The information required in paragraphs (a) (1), (2), and (3) of this section should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in § 61.10(a).

(b) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section whenever

there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(c) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(d) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Administrator the following reports:

(1) Within 90 days after January 7, 1993, unless a waiver of compliance under §61.11 of this part is granted, or by the date of initial startup for a new source with an initial startup after the effective date, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with this subpart. If a waiver of compliance is granted under §61.11, the certification of equipment necessary to comply with these standards shall be submitted by the date the waiver of compliance expires.

(2) Beginning on the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in

the following year, the owner or operator may submit a statement to that effect.

(3) If an owner or operator elects to comply with the requirements of §61.342(c)(3)(ii), then the report required by paragraph (d)(2) of this section shall include a table identifying each waste stream chosen for exemption and the total annual benzene quantity in these exempted streams.

(4) If an owner or operator elects to comply with the alternative requirements of §61.342(d) of this subpart, then he shall include in the report required by paragraph (d)(2) of this section a table presenting the following information for each process wastewater stream:

(i) Whether or not the process wastewater stream is being controlled for benzene emissions in accordance with the requirements of this subpart;

(ii) For each process wastewater stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(iii) For each process wastewater stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the exit to the treatment process: Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(5) If an owner or operator elects to comply with the alternative requirements of §61.342(e), then the report required by paragraph (d)(2) of this section shall include a table presenting the following information for each waste stream:

(i) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information

for the waste stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(ii) For each waste stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the waste stream as determined at the applicable location described in §61.355(k)(2): Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(6) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit quarterly to the Administrator a certification that all of the required inspections have been carried out in accordance with the requirements of this subpart.

(7) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit a report quarterly to the Administrator that includes:

(i) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(a)(1) of this subpart, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than 10 ppmw.

(ii) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(a)(2) of this subpart, then each 3-hour period of operation during which the average value of the monitored parameter is outside the range of acceptable values or during which the unit is not operating as designed.

(iii) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(b), then each period of operation during which the flow-weighted annual average concentration of benzene in the monitored waste stream entering the

unit is equal to or greater than 10 ppmw and/or the total annual benzene quantity is equal to or greater than 1.0 mg/yr.

(iv) For a control device monitored in accordance with §61.354(c) of this subpart, each period of operation monitored during which any of the following conditions occur, as applicable to the control device:

(A) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(B) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference.

(C) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a boiler or process heater having a design heat input capacity less than 44 MW (150 × 10⁶ BTU/hr), as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(D) Each 3-hour period of operation during which the average concentration of organics or the average concentration of benzene in the exhaust gases from a carbon adsorber, condenser, or other vapor recovery system is more than 20 percent greater than the design concentration level of organics or benzene in the exhaust gas.

(E) Each 3-hour period of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature,

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or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(F) Each period in which the pilot flame of a flare is absent.

(G) Each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone of a boiler or process heater as required by §61.349(a)(2)(i)(C) of this subpart.

(H) Each occurrence when the carbon in a carbon adsorber system that is regenerated directly on site in the control device is not regenerated at the predetermined carbon bed regeneration time.

(I) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly on site in the control device is not replaced at the predetermined interval specified in §61.354(c) of this subpart.

(J) Each 3-hour period of operation during which the parameters monitored are outside the range of values specified in §61.349(a)(2)(iv)(C), or any other periods specified by the Administrator for a control device subject to the requirements of §61.349(a)(2)(iv).

(v) For a cover and closed-vent system monitored in accordance with §61.354(g), the owner or operator shall submit a report quarterly to the Administrator that identifies any period in which the pressure in the waste management unit is equal to or greater than atmospheric pressure.

(8) Beginning one year after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Ad-

ministrator a report that summarizes all inspections required by §§61.342 through 61.354 during which detectable emissions are measured or a problem (such as a broken seal, gap or other problem) that could result in benzene emissions is identified, including information about the repairs or corrective action taken.

(e) An owner or operator electing to comply with the provisions of §§61.351 or 61.352 of this subpart shall notify the Administrator of the alternative standard selected in the report required under §61.07 or §61.10 of this part.

(f) An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b.

(g) An owner or operator who elects to install and operate the control equipment in §61.352 of this subpart shall submit initial and quarterly reports that identify all seal gap measurements, as required in 40 CFR 60.693-2(a), that are outside the prescribed limits.

[55 FR 8346, Mar. 7 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3105, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000]

§61.358 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Clean Air Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Alternative means of emission limitation under §61.353 of this subpart will not be delegated to States.

§61.359 [Reserved]

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Appendix F Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

(d) The requirements of this subsection remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected sources within the State will be relieved of the obligation to comply with this subsection, provided that they comply with requirements established by the State.

Subpart GGG—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

SOURCE: 49 FR 22606, May 30, 1984, unless otherwise noted.

§ 60.590 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in § 60.591) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction or modification after January 4, 1983, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in § 60.591) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV or subpart KKK of 40 CFR part 60 are excluded from this subpart.

§ 60.591 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the act, in subpart A of part 60, or in subpart VV of part 60, and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.

Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

In hydrogen service means that a compressor contains a process fluid that meets the conditions specified in § 60.593(b).

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.593(c).

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

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Process unit means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

§ 60.592 Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§ 60.482-1 to 60.482-10 as soon as practicable, but no later than 180 days after initial startup.

(b) An owner or operator may elect to comply with the requirements of §§ 60.483-1 and 60.483-2.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.484.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of § 60.485 except as provided in § 60.593.

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(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§ 60.486 and 60.487.

§ 60.593 Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VV.

(b)(1) Compressors in hydrogen service are exempt from the requirements of § 60.592 if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260-73, 91, or 96, E168-67, 77, or 92, or E169-63, 77, or 93 (incorporated by reference as specified in § 60.17) shall be used.

(3)(i) An owner or operator may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from § 60.482 (a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the com-

pressor are the only options available to bring the compressor into compliance with the provisions of § 60.482 (a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to § 60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.18).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of § 60.482-2 and § 60.482-7.

[49 FR 22606, May 30, 1984, as amended at 65 FR 61768, Oct. 17, 2000]

Subpart HHH—Standards of Performance for Synthetic Fiber Production Facilities

SOURCE: 49 FR 13651, Apr. 5, 1984, unless otherwise noted.

§ 60.600 Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which the provisions of this subpart apply is each solvent-spun synthetic fiber process that produces more than 500 Mg (551 ton) of fiber per year.

(b) The provisions of this subpart do not apply to any facility that uses the reaction spinning process to produce spandex fiber or the viscose process to produce rayon fiber.

(c) The provisions of this subpart apply to each facility as identified in paragraph (a) of this section and that commences construction or reconstruction after November 23, 1982. The provisions of this subpart do not apply to facilities that commence modification but not reconstruction after November 23, 1982.

[49 FR 22606, May 30, 1984, as amended at 65 FR 61768, Oct. 17, 2000]

§ 60.601 Definitions.

All terms that are used in this subpart and are not defined below are given the same meaning as in the Act and in subpart A of this part.

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Appendix G Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

§ 60.480

where:

P=asphalt charging rate to blowing still, Mg/hr (ton/hr).

V=volume of asphalt charged, m³ (ft³).

d=density of asphalt, kg/m³ (lb/ft³).

K'=conversion factor, 1000 kg/Mg (2000 lb/ton).

t=duration of test run, hr.

(i) The volume (V) of asphalt charged shall be measured by any means accurate to within 10 percent.

(ii) The density (d) of the asphalt shall be computed using the following equation:

$$d = K_1 - K_2 T_1$$

Where:

d = Density of the asphalt, kg/m³ (lb/ft³)

K₁ = 1056.1 kg/m³ (metric units)

= 64.70 lb/ft³ (English Units)

K₂ = 0.6176 kg/(m³ °C) (metric units)

= 0.0694 lb/(ft³ °F) (English Units)

T₁ = temperature at the start of the blow, °C (°F)

(5) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

(d) The Administrator will determine compliance with the standards in § 60.472(a)(3) by using Method 22, modified so that readings are recorded every 15 seconds for a period of consecutive observations during representative conditions (in accordance with § 60.8(c)) totaling 60 minutes. A performance test shall consist of one run.

(e) The owner or operator shall use the monitoring device in § 60.473 (a) or (b) to monitor and record continuously the temperature during the particulate matter run and shall report the results to the Administrator with the performance test results.

(f) If at a later date the owner or operator believes that the emission limits in § 60.472(a) and (b) are being met even though one of the conditions listed in this paragraph exist, he may submit a written request to the Administrator to repeat the performance test and procedure outlined in paragraph (c) of this section.

(1) The temperature measured in accordance with § 60.473(a) is exceeding that measured during the performance test.

(2) The temperature measured in accordance with § 60.473(b) is lower than

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that measured during the performance test.

(g) If fuel oil is to be used to fire an afterburner used to control emissions from a blowing still, the owner or operator may petition the Administrator in accordance with § 60.11(e) of the General Provisions to establish an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. To obtain this opacity standard, the owner or operator must request the Administrator to determine opacity during an initial, or subsequent, performance test when fuel oil is used to fire the afterburner. Upon receipt of the results of the performance test, the Administrator will make a finding concerning compliance with the mass standard for the blowing still. If the Administrator finds that the facility was in compliance with the mass standard during the performance test but failed to meet the zero opacity standard, the Administrator will establish and promulgate in the FEDERAL REGISTER an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. When the afterburner is fired with natural gas, the zero percent opacity remains the applicable opacity standard.

[54 FR 6677, Feb. 14, 1989, as amended 54 FR 27016, June 27, 1989; 65 FR 61762, Oct. 17, 2000]

Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

SOURCE: 48 FR 48335, Oct. 18, 1983, unless otherwise noted.

§ 60.480 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction or modification

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after January 5, 1981, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) is exempt from § 60.482.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from § 60.482.

(4) Any affected facility that produces beverage alcohol is exempt from § 60.482.

(5) Any affected facility that has no equipment in VOC service is exempt from § 60.482.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482 through 60.487 for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of § 60.485(d), (e), and (f), and § 60.486(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part

65, subpart F, must comply with 40 CFR part 65, subpart A.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000]

§ 60.481 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of part 60, and the following terms shall have the specific meanings given them.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 1982 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

TABLE FOR DETERMINING APPLICABLE FOR B

Subpart applicable to facility	Value of B to be used in equation
VV	12.5
DDD	12.5
GGG	7.0
KKK	4.5

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, welded, or other joined fittings used to

connect two pipe lines or a pipe line and a piece of process equipment.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take rapid action for the purpose of stopping or reducing leakage of organic material to atmosphere using best practices.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, PO Box 2900, Fairfield, NJ 07007-2900).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485(e).

In-situ sampling systems means non-extractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa)(0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485(d) specify how to determine that a piece of equipment is not in VOC service.)

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of

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equipment without stopping production are not process unit shutdowns.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as indicated by one of the following: an instrument reading of 10,000 ppm or greater, indication of liquids dripping, or indication by a sensor that a seal or barrier fluid system has failed.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in § 60.2 Definitions.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 49 FR 26738, June 29, 1984; 60 FR 43258, Aug. 18, 1995; 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000]

§ 60.482-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§ 60.482-1 through 60.482-10 or § 60.480(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§ 60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the

requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in § 60.484.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, or 60.482-10, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§ 60.482-2 to 60.482-10 if it is identified as required in § 60.486(e)(5).

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 78276, Dec. 14, 2000]

§ 60.482-2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485(b), except as provided in § 60.482-1(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a), *Provided* the following requirements are met:

(1) Each dual mechanical seal system is—

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipment with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control

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device that complies with the requirements of § 60.482-10; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm, and

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(6)(i) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined in paragraph (d)(5)(ii), a leak is detected.

(ii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(iii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any pump that is designated, as described in § 60.486(e)(1) and (2), for no detectable emission, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485(c), and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

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(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of § 60.482-10, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in § 60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000]

§ 60.482-3 Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482-1(c) and paragraph (h) and (i) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed

to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482-10; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of § 60.482-10, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in § 60.486(e) (1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)-(h) if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as

measured by the methods specified in § 60.485(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from § 60.482(a), (b), (c), (d), (e), and (h), provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000]

§ 60.482-4 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482-9.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482-10 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in § 60.482-9.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000]

§ 60.482-5 Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in § 60.482-1(c). Gases displaced during filling of the sample container are not required to be collected or captured.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section:

(1) Return the purged process fluid directly to the process line; or

(2) Collect and recycle the purged process fluid to a process; or

(3) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482-10; or

(4) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(i) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to, and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(ii) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266; or

(iii) A facility permitted, licensed, or registered by a State to manage municipal or industrial solid waste, if the

process fluids are not hazardous waste as defined in 40 CFR part 261.

(c) In situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

[60 FR 43258, Aug. 18, 1995, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000]

§ 60.482-6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1(c).

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b) and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 65 FR 78277, Dec. 14, 2000]

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§ 60.482-7 Standards: Valves in gas/vapor service and in light liquid service.

(a) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485(b) and shall comply with paragraphs (b) through (e), except as provided in paragraphs (f), (g), and (h), § 60.483-1, 2, and § 60.482-1(c).

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

- (1) Tightening of bonnet bolts;
- (2) Replacement of bonnet bolts;
- (3) Tightening of packing gland nuts;
- (4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.485(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486(f)(1), as an unsafe-

to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a), and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either becomes an affected facility through § 60.14 or § 60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor, and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 61762, Oct. 17, 2000]

§ 60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in § 60.485(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak.

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(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under § 60.482-7(e).

[48 CFR 48335, Oct. 18, 1983, as amended at 65 FR 78277, Dec. 14, 2000]

§ 60.482-9 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482-10.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless

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the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 78277, Dec. 14, 2000]

§ 60.482-10 Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (f)(1)(ii) of this section:

(i) Conduct an initial inspection according to the procedures in § 60.485(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in § 60.485(b); and

(ii) Conduct annual inspections according to the procedures in § 60.485(b).

(g) Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (j)(2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (k)(3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§ 60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (l)(5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486(c).

(4) For each inspection conducted in accordance with § 60.485(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

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(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

[48 FR 48335, Oct. 18, 1983, as amended at 51 FR 2702, Jan. 21, 1986; 60 FR 43258, Aug. 18, 1995; 61 FR 29878, June 12, 1996; 65 FR 78277, Dec. 14, 2000]

§ 60.483-1 Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482-7(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000]

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§ 60.483-2 Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487(d).

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7 but can again elect to use this section.

(5) The percent of valves leaking shall be determined by dividing the sum of valves found leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements of this section.

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000]

§ 60.484 Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least

equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

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

(2) The Administrator will compare test data for the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

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

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

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

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

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work

practices and will consider the commitment in paragraph (c)(4).

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

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

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

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

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000]

§ 60.485 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§ 60.482, 60.483, and 60.484 as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(c) The owner or operator shall determine compliance with the no detectable emission standards in §§ 60.482-2(e), 60.482-3(i), 60.482-4, 60.482-7(f), and 60.482-10(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d) (1) and (2) of this

section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that an equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{\max} = K_1 + K_2 H_T$$

Where:

V_{\max} = Maximum permitted velocity, m/sec (ft/sec)

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units)

= 28.56 ft/sec (English units)

K_2 = 0.7084 m³/(MJ-sec) (metric units)

= 0.087 ft³/(Btu-sec) (English units)

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

K = Conversion constant, 1.740×10^7 (g-mole)(MJ)/(ppm-scm-kcal) (metric units)

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$= 4.674 \times 10^8 [(g\text{-mole})(Btu)/(ppm\text{-scf-kcal})]$
(English units)

C_i = Concentration of sample component "i,"
ppm

H_i = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole

(5) Method 18 and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference—see § 60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference—see § 60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

[54 FR 6678, Feb. 14, 1989, as amended at 54 FR 27016, June 27, 1989; 65 FR 61763, Oct. 17, 2000]

§ 60.486 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(b) When each leak is detected as specified in §§ 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following in-

formation shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) "Above 10,000" if the maximum instrument reading measured by the methods specified in § 60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482-10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482-10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§ 60.482-2, 60.482-3, 60.482-4, and 60.482-5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control

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devices required in §§ 60.482-2, 60.482-3, 60.482-4, and 60.482-5.

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482-1 to 60.482-10 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§ 60.482-2(e), 60.482-3(i) and 60.482-7(f).

(ii) The designation of equipment as subject to the requirements of § 60.482-2(e), § 60.482-3(i), or § 60.482-7(f) shall be signed by the owner or operator.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482-4.

(4)(i) The dates of each compliance test as required in §§ 60.482-2(e), 60.482-3(i), 60.482-4, and 60.482-7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(f) The following information pertaining to all valves subject to the requirements of § 60.482-7(g) and (h) and to all pumps subject to the requirements of § 60.482-2(g) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with § 60.483-2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§ 60.482-2(d)(5) and 60.482-3(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of § 60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61763, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000]

§ 60.487 Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning six months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482-7, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7(f).

(3) Number of pumps subject to the requirements of § 60.482-2, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2(e) and those pumps complying with § 60.482-2(f).

(4) Number of compressors subject to the requirements of § 60.482-3, excluding those compressors designated for no detectable emissions under the provisions

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of § 60.482-3(i) and those compressors complying with § 60.482-3(h).

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482-7(b) or § 60.483-2,

(ii) Number of valves for which leaks were not repaired as required in § 60.482-7(d)(1),

(iii) Number of pumps for which leaks were detected as described in § 60.482-2(b) and (d)(6)(i),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482-2(c)(1) and (d)(6)(ii),

(v) Number of compressors for which leaks were detected as described in § 60.482-3(f),

(vi) Number of compressors for which leaks were not repaired as required in § 60.482-3(g)(1), and

(vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§ 60.483-1 or 60.483-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in dele-

gating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the State.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 61763, Oct. 17, 2000]

§ 60.488 Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable new facility" under § 60.15: pump seals, nuts and bolts, rupture disks, and packings.

(b) Under § 60.15, the "fixed capital cost of new components" includes the fixed capital cost of all depreciable components (except components specified in § 60.488 (a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the "Applicability and designation of affected facility" section of the appropriate subpart.) For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[49 FR 22608, May 30, 1984]

§ 60.489 List of chemicals produced by affected facilities.

The following chemicals are produced, as intermediates or final products, by process units covered under this subpart. The applicability date for process units producing one or more of these chemicals is January 5, 1981.

CAS No. *	Chemical	CAS No. *	Chemical
105-57-7	Acetal.	106-31-0	Butyric anhydride.
75-07-0	Acetaldehyde.	109-74-0	Butyronitrile.
107-89-1	Acetalddol.	105-60-2	Caprolactam.
60-35-5	Acetamide.	75-1-50	Carbon disulfide.
103-84-4	Acetanilide.	558-13-4	Carbon tetrabromide.
64-19-7	Acetic acid.	56-23-5	Carbon tetrachloride.
108-24-7	Acetic anhydride.	9004-35-7	Cellulose acetate.
67-64-1	Acetone.	79-11-8	Chloroacetic acid.
75-86-5	Acetone cyanohydrin.	108-42-9	m-chloroaniline.
75-05-8	Acetonitrile.	95-51-2	o-chloroaniline.
98-86-2	Acetophenone.	106-47-8	p-chloroaniline.
75-36-5	Acetyl chloride.	35913-09-8	Chlorobenzaldehyde.
74-86-2	Acetylene.	108-90-7	Chlorobenzene.
107-02-8	Acrolein.	118-91-2, 535-80-8, 74-11-3	Chlorobenzoic acid.
79-06-1	Acrylamide.	2136-81-4,	Chlorobenzotrithloride.
79-10-7	Acrylic acid.	2136-89-2,	
107-13-1	Acrylonitrile.	5216-25-1	
124-04-9	Adipic acid.	1321-03-5	Chlorobenzoyl chloride.
111-69-3	Adiponitrile.	25497-29-4	Chlorodifluoromethane.
(b)	Alkyl naphthalenes.	75-45-6	Chlorodifluoroethane.
107-18-6	Allyl alcohol.	67-66-3	Chloroform.
107-05-1	Allyl chloride.	25586-43-0	Chloronaphthalene.
1321-11-5	Aminobenzoic acid.	88-73-3	o-chloronitrobenzene.
111-41-1	Aminoethylethanamine.	100-00-5	p-chloronitrobenzene.
123-30-8	p-Aminophenol.	25167-80-0	Chlorophenols.
628-63-7, 123-92-2.	Amyl acetates.	126-99-8	Chloroprene.
71-41-0	Amyl alcohols.	7790-94-5	Chlorosulfonic acid.
110-58-7	Amyl amine.	108-41-8	m-chlorotoluene.
543-59-9	Amyl chloride.	95-49-8	o-chlorotoluene.
110-66-7	Amyl mercaptans.	106-43-4	p-chlorotoluene.
1322-06-1	Amyl phenol.	75-72-9	Chlorotrifluoromethane.
62-53-3	Aniline.	108-39-4	m-cresol.
142-04-1	Aniline hydrochloride.	95-48-7	o-cresol.
29191-52-4	Anisidine.	106-44-5	p-cresol.
100-66-3	Anisole.	1319-77-3	Mixed cresols.
118-92-3	Anthranilic acid.	1319-77-3	Cresylic acid.
84-65-1	Anthraquinone.	4170-30-0	Crotonaldehyde.
100-52-7	Benzaldehyde.	3724-65-0	Crotonic acid.
55-21-0	Benzamide.	98-82-8	Cumene.
71-43-2	Benzene.	80-15-9	Cumene hydroperoxide.
98-48-6	Benzenedisulfonic acid.	372-09-8	Cyanoacetic acid.
98-11-3	Benzenesulfonic acid.	508-77-4	Cyanogen chloride.
134-81-6	Benzil.	108-80-5	Cyanuric acid.
78-83-7	Benzilic acid.	108-77-0	Cyanuric chloride.
65-85-0	Benzoic acid.	110-82-7	Cyclohexane.
119-53-9	Benzoin.	108-93-0	Cyclohexanol.
100-47-0	Benzonitrile.	108-94-1	Cyclohexanone.
119-51-9	Benzophenone.	110-83-8	Cyclohexane.
98-07-7	Benzotrithloride.	108-91-8	Cyclohexylamine.
98-88-4	Benzoyl chloride.	111-78-4	Cyclooctadiene.
100-51-6	Benzyl alcohol.	112-30-1	Decanol.
100-46-9	Benzylamine.	123-42-2	Diacetone alcohol.
120-51-4	Benzyl benzoate.	27576-04-1	Diaminobenzoic acid.
100-44-7	Benzyl chloride.	95-76-1, 95-82-9, 554-00-7,	Dichloroaniline.
98-87-3	Benzyl dichloride.	608-27-5,	
92-52-4	Biphenyl.	608-31-1,	
80-05-7	Bisphenol A.	626-43-7,	
10-86-1	Bromobenzene.	27134-27-6,	
27497-51-4	Bromonaphthalene.	57311-92-9	
106-99-0	Butadiene.	541-73-1	m-dichlorobenzene.
106-98-9	1-butene.	95-50-1	o-dichlorobenzene.
123-86-4	n-butyl acetate.	108-46-7	p-dichlorobenzene.
141-32-2	n-butyl acrylate.	75-71-8	Dichlorodifluoromethane.
71-36-3	n-butyl alcohol.	111-44-4	Dichloroethyl ether.
78-92-2	s-butyl alcohol.	107-06-2	1,2-dichloroethane (EDC).
75-65-0	t-butyl alcohol.	96-23-1	Dichlorohydrin.
109-73-9	n-butylamine.	26952-23-8	Dichloropropene.
13952-84-6	s-butylamine.	101-83-7	Dicyclohexylamine.
75-64-9	t-butylamine.	109-89-7	Diethylamine.
98-73-7	p-terti-butyl benzoic acid.	111-46-6	Diethylene glycol.
107-88-0	1,3-butylene glycol.	112-36-7	Diethylene glycol diethyl ether.
123-72-8	n-butyraldehyde.		
107-92-6	Butyric acid.		

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CAS No. *	Chemical	CAS No. *	Chemical
111-96-6	Diethylene glycol dimethyl ether.	110-17-8	Fumaric acid.
112-34-5	Diethylene glycol monobutyl ether.	98-01-1	Furfural.
124-17-4	Diethylene glycol monobutyl ether ace- tate.	56-81-5	Glycerol.
111-90-0	Diethylene glycol monoethyl ether.	26545-73-7	Glycerol dichlorohydrin.
112-15-2	Diethylene glycol monoethyl ether ace- tate.	25791-86-2	Glycerol triether.
111-77-3	Diethylene glycol monomethyl ether.	56-40-6	Glycine.
64-67-5	Diethyl sulfate.	107-22-2	Glyoxal.
75-37-6	Difluoroethane.	118-74-1	Hexachlorobenzene.
25167-70-8	Diisobutylene.	67-72-1	Hexachloroethane.
26761-40-0	Disodecyl phthalate.	36653-82-4	Hexadecyl alcohol.
27554-26-3	Diisooctyl phthalate.	124-09-4	Hexamethylenediamine.
674-82-8	Diketene.	629-11-8	Hexamethylene glycol.
124-40-3	Dimethylamine.	100-97-0	Hexamethylenetetramine.
121-69-7	N,N-dimethylaniline.	74-90-8	Hydrogen cyanide.
115-10-6	N,N-dimethyl ether.	123-31-9	Hydroquinone.
68-12-2	N,N-dimethylformamide.	99-96-7	p-hydroxybenzoic acid.
57-14-7	Dimethylhydrazine.	26760-64-5	Isoamylene.
77-78-1	Dimethyl sulfate.	78-83-1	Isobutanol.
75-18-3	Dimethyl sulfide.	110-19-0	Isobutyl acetate.
67-68-5	Dimethyl sulfoxide.	115-11-7	Isobutylene.
120-61-6	Dimethyl terephthalate.	78-84-2	Isobutyraldehyde.
98-34-3	3,5-dinitrobenzoic acid.	79-31-2	Isobutyric acid.
51-28-5	Dinitrophenol.	25339-17-7	Isodecanol.
25321-14-6	Dinitrotoluene.	26952-21-6	Isooctyl alcohol.
123-91-1	Dioxane.	78-78-4	Isopentane.
646-06-0	Dioxilane.	78-59-1	Isophorone.
122-39-4	Diphenylamine.	121-91-5	Isophthalic acid.
101-84-8	Diphenyl oxide.	78-79-5	Isoprene.
102-08-9	Diphenyl thiourea.	67-63-0	Isopropanol.
25265-71-8	Dipropylene glycol.	108-21-4	Isopropyl acetate.
25378-22-7	Dodecene.	75-31-0	Isopropylamine.
28675-17-4	Dodecylaniline.	75-28-6	Isopropyl chloride.
27193-86-8	Dodecylphenol.	25166-06-3	Isopropylphenol.
106-89-8	Epichlorohydrin.	463-51-4	Kelene.
64-17-5	Ethanol.	(*)	Linear alkyl sulfonate.
141-43-5	Ethanolamines.	123-01-3	Linear alkylbenzene (linear dodecylbenzene).
141-78-6	Ethyl acetate.	110-16-7	Maleic acid.
141-97-9	Ethyl acetoacetate.	108-31-6	Maleic anhydride.
140-88-5	Ethyl acrylate.	6915-15-7	Malic acid.
75-04-7	Ethylamine.	141-79-7	Mesityl oxide.
100-41-4	Ethylbenzene.	121-47-1	Metanilic acid.
74-96-4	Ethyl bromide.	79-41-4	Methacrylic acid.
9004-57-3	Ethylcellulose.	563-47-3	Methallyl chloride.
75-00-3	Ethyl chloride.	67-56-1	Methanol.
105-39-5	Ethyl chloroacetate.	79-20-9	Methyl acetate.
105-56-6	Ethylcyanoacetate.	105-45-3	Methyl acetoacetate.
74-85-1	Ethylene.	74-89-5	Methylamine.
96-49-1	Ethylene carbonate.	100-61-8	n-methylaniline.
107-07-3	Ethylene chlorohydrin.	74-83-9	Methyl bromide.
107-15-3	Ethylenediamine.	37365-71-2	Methyl butynol.
106-93-4	Ethylene dibromide.	74-87-3	Methyl chloride.
107-21-1	Ethylene glycol.	108-87-2	Methylcyclohexane.
111-55-7	Ethylene glycol diacetate.	1331-22-2	Methylcyclohexanone.
110-71-4	Ethylene glycol dimethyl ether.	75-06-2	Methylene chloride.
111-76-2	Ethylene glycol monobutyl ether.	101-77-9	Methylene dianiline.
112-07-2	Ethylene glycol monobutyl ether acetate.	101-68-8	Methylene diphenyl diisocyanate.
110-80-5	Ethylene glycol monoethyl ether.	78-93-3	Methyl ethyl ketone.
111-15-9	Ethylene glycol monomethyl ether acetate.	107-31-3	Methyl formate.
109-86-4	Ethylene glycol monomethyl ether.	108-11-2	Methyl isobutyl carbinol.
110-49-6	Ethylene glycol monomethyl ether ace- tate.	108-10-1	Methyl isobutyl ketone.
122-99-6	Ethylene glycol monophenyl ether.	80-62-6	Methyl methacrylate.
2807-30-9	Ethylene glycol monopropyl ether.	77-75-8	Methylpentynol.
75-21-8	Ethylene oxide.	98-83-9	a-methylstyrene.
60-29-7	Ethyl ether.	110-91-8	Morpholine.
104-76-7	2-ethylhexanol.	85-47-2	a-naphthalene sulfonic acid.
122-51-0	Ethyl orthoformate.	120-18-3	b-naphthalene sulfonic acid.
95-92-1	Ethyl oxalate.	90-15-3	a-naphthol.
41892-71-1	Ethyl sodium oxalacetate.	135-19-3	b-naphthol.
50-00-0	Formaldehyde.	75-98-9	Neopentanoic acid.
75-12-7	Formamide.	88-74-4	o-nitroaniline.
64-18-6	Formic acid.	100-01-6	p-nitroaniline.
		91-23-6	o-nitroanisole.
		100-17-4	p-nitroanisole.

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CAS No. *	Chemical
98-95-3	Nitrobenzene.
27178-83-2 ^a	Nitrobenzoic acid (o,m, and p).
76-24-3	Nitroethane.
75-52-5	Nitromethane.
88-75-5	2-Nitrophenol.
25322-01-4	Nitropropane.
1321-12-6	Nitrotoluene.
27215-95-8	Nonene.
25154-52-3	Nonylphenol.
27193-26-8	Octylphenol.
123-83-7	Paraldehyde.
115-77-5	Pentaerythritol.
109-66-0	n-pentane.
109-67-1	1-pentene.
127-18-4	Perchloroethylene.
594-42-3	Perchloromethyl mercaptan.
94-70-2	o-phenetidine.
156-43-4	p-phenetidine.
108-95-2	Phenol.
98-67-9, 585-39-6, 609-46-1, 1333-39-7 ^b	Phenolsulfonic acids.
91-40-7	Phenyl anthranilic acid.
(^b)	Phenylenediamine.
75-44-5	Phosgene.
85-44-9	Phthalic anhydride.
85-41-6	Phthalimide.
108-99-6	p-picoline.
110-85-0	Piperazine.
9003-29-6, 25036-29-7 ^c	Polybutenes.
25322-68-3	Polyethylene glycol.
25322-69-4	Polypropylene glycol.
123-38-6	Propionaldehyde.
79-09-4	Propionic acid.
71-23-8	n-propyl alcohol.
107-10-8	Propylamine.
540-54-5	Propyl chloride.
115-07-1	Propylene.
127-00-4	Propylene chlorohydrin.
78-87-5	Propylene dichloride.
57-55-6	Propylene glycol.
75-56-9	Propylene oxide.
110-86-1	Pyridine.
106-51-4	Quinone.
108-46-3	Resorcinol.
27138-57-4	Resorcylic acid.
69-72-7	Salicylic acid.
127-08-3	Sodium acetate.
532-32-1	Sodium benzoate.
9004-32-4	Sodium carboxymethyl cellulose.
3926-62-3	Sodium chloroacetate.
141-53-7	Sodium formate.
139-02-6	Sodium phenate.
110-44-1	Sorbic acid.
100-42-5	Styrene.
110-15-6	Succinic acid.
110-81-2	Succinonitrile.
121-57-3	Sulfanilic acid.
126-33-0	Sulfolane.
1401-55-4	Tannic acid.
100-21-0	Terephthalic acid.
79-34-5 ^c	Tetrachloroethanes.
117-08-8	Tetrachlorophthalic anhydride.
78-00-2	Tetraethyl lead.
119-64-2	Tetrahydronaphthalene.
85-43-8	Tetrahydrophthalic anhydride.
75-74-1	Tetramethyl lead.
110-60-1	Tetramethylenediamine.
110-18-9	Tetramethylethylenediamine.
108-88-3	Toluene.
95-80-7	Toluene-2,4-diamine.
584-84-9	Toluene-2,4-diisocyanate.
26471-62-5	Toluene diisocyanates (mixture).

CAS No. *	Chemical
1333-07-9	Toluenesulfonamide.
104-15-4 ^a	Toluenesulfonic acids.
98-59-9	Toluenesulfonyl chloride.
26915-12-8	Toluidines.
87-61-6, 108-70-3, 120-82-1 ^c	Trichlorobenzenes.
71-55-6	1,1,1-trichloroethane.
79-00-5	1,1,2-trichloroethane.
79-01-6	Trichloroethylene.
75-69-4	Trichlorofluoromethane.
96-18-4	1,2,3-trichloropropane.
76-13-1	1,1,2-trichloro-1,2,2-trifluoroethane.
121-44-8	Triethylamine.
112-27-6	Triethylene glycol.
112-49-2	Triethylene glycol dimethyl ether.
7756-94-7	Triisobutylene.
75-50-3	Trimethylamine.
57-13-6	Urea.
108-05-4	Vinyl acetate.
75-01-4	Vinyl chloride.
75-35-4	Vinylidene chloride.
25013-15-4	Vinyl toluene.
1330-20-7	Xylenes (mixed).
95-47-6	o-xylene.
106-42-3	p-xylene.
1300-71-6	Xylenol.
1300-73-8	Xylidine.

*CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

^bNo CAS number(s) have been assigned to this chemical, its isomers, or mixtures containing these chemicals.

^cCAS numbers for some of the isomers are listed; the standards apply to all of the isomers and mixtures, even if CAS numbers have not been assigned.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61763, Oct. 17, 2000]

Subpart WW—Standards of Performance for the Beverage Can Surface Coating Industry

SOURCE: 48 FR 38737, Aug. 25, 1983, unless otherwise noted.

§ 60.490 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in beverage can surface coating lines: each exterior base coat operation, each overvarnish coating operation, and each inside spray coating operation.

(b) The provisions of this subpart apply to each affected facility which is identified in paragraph (a) of this section and commences construction, modification, or reconstruction after November 26, 1980.

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Appendix H Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

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

(5) Method 3 for gas analysis; and

(6) Method 4 for stack gas moisture.

(b) For Method 24, the coating sample must be at least a 1-liter sample taken at a point where the sample will be representative of the coating as applied to the surface of the metal coil.

(c) For Method 25, the sampling time for each of three runs is to be at least 60 minutes, and the minimum sampling volume is to be at least 0.003 dscm (0.11 dscf); however, shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(d) The Administrator will approve testing of representative stacks on a case-by-case basis if the owner or operator can demonstrate to the satisfaction of the Administrator that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks.

[47 FR 49612, Nov. 1, 1982, as amended at 51 FR 22938, June 24, 1986; 65 FR 61761, Oct. 17, 2000]

Subpart UU—Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

SOURCE: 47 FR 34143, Aug. 6, 1982, unless otherwise noted.

§ 60.470 Applicability and designation of affected facilities.

(a) The affected facilities to which this subpart applies are each saturator and each mineral handling and storage facility at asphalt roofing plants; and each asphalt storage tank and each blowing still at asphalt processing plants, petroleum refineries, and asphalt roofing plants.

(b) Any saturator or mineral handling and storage facility under paragraph (a) of this section that commences construction or modification after November 18, 1980, is subject to the requirements of this subpart. Any asphalt storage tank or blowing still that processes and/or stores asphalt used for roofing only or for roofing and other purposes, and that commences construction or modification after No-

vember 18, 1980, is subject to the requirements of this subpart.

Any asphalt storage tank or blowing still that processes and/or stores only nonroofing asphalts and that commences construction or modification after May 26, 1981, is subject to the requirements of this subpart.

§ 60.471 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Afterburner (A/B) means an exhaust gas incinerator used to control emissions of particulate matter.

Asphalt processing means the storage and blowing of asphalt.

Asphalt processing plant means a plant which blows asphalt for use in the manufacture of asphalt products.

Asphalt roofing plant means a plant which produces asphalt roofing products (shingles, roll roofing, siding, or saturated felt).

Asphalt storage tank means any tank used to store asphalt at asphalt roofing plants, petroleum refineries, and asphalt processing plants. Storage tanks containing cutback asphalts (asphalts diluted with solvents to reduce viscosity for low temperature applications) and emulsified asphalts (asphalts dispersed in water with an emulsifying agent) are not subject to this regulation.

Blowing still means the equipment in which air is blown through asphalt flux to change the softening point and penetration rate.

Catalyst means a substance which, when added to asphalt flux in a blowing still, alters the penetrating-softening point relationship or increases the rate of oxidation of the flux.

Coating blow means the process in which air is blown through hot asphalt flux to produce coating asphalt. The coating blow starts when the air is turned on and stops when the air is turned off.

Electrostatic precipitator (ESP) means an air pollution control device in which solid or liquid particulates in a gas stream are charged as they pass through an electric field and precipitated on a collection surface.

High velocity air filter (HVAF) means an air pollution control filtration device for the removal of sticky, oily, or liquid aerosol particulate matter from exhaust gas streams.

Mineral handling and storage facility means the areas in asphalt roofing plants in which minerals are unloaded from a carrier, the conveyor transfer points between the carrier and the storage silos, and the storage silos.

Saturator means the equipment in which asphalt is applied to felt to make asphalt roofing products. The term saturator includes the saturator, wet looper, and coater.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000]

§ 60.472 Standards for particulate matter.

(a) On and after the date on which § 60.8(b) requires a performance test to be completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any saturator:

(1) Particulate matter in excess of:

(i) 0.04 kg/Mg (0.08 lb/ton) of asphalt shingle or mineral-surfaced roll roofing produced, or

(ii) 0.04 kg/Mg (0.08 lb/ton) of saturated felt or smooth-surfaced roll roofing produced;

(2) Exhaust gases with opacity greater than 20 percent; and

(3) Any visible emissions from a saturator capture system for more than 20 percent of any period of consecutive valid observations totaling 60 minutes. Saturators that were constructed before November 18, 1980, and that have not been reconstructed since that date and that become subject to these standards through modification are exempt from the visible emissions standard. Saturators that have been newly constructed or reconstructed since November 18, 1980 are subject to the visible emissions standard.

(b) On and after the date on which § 60.8(b) requires a performance test to be completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blowing still:

(1) Particulate matter in excess of 0.67 kg/Mg (1.3 lb/ton) of asphalt

charged to the still when a catalyst is added to the still; and

(2) Particulate matter in excess of 0.71 kg/Mg (1.4 lb/ton) of asphalt charged to the still when a catalyst is added to the still and when No. 6 fuel oil is fired in the afterburner; and

(3) Particulate matter in excess of 0.60 kg/Mg (1.2 lb/ton) of asphalt charged to the still during blowing without a catalyst; and

(4) Particulate matter in excess of 0.64 kg/Mg (1.3 lb/ton) of asphalt charged to the still during blowing without a catalyst and when No. 6 fuel oil is fired in the afterburner; and

(5) Exhaust gases with an opacity greater than 0 percent unless an opacity limit for the blowing still when fuel oil is used to fire the afterburner has been established by the Administrator in accordance with the procedures in § 60.474(g).

(c) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any asphalt storage tank exhaust gases with opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. The control device shall not be bypassed during this 15-minute period. If, however, the emissions from any asphalt storage tank(s) are ducted to a control device for a saturator, the combined emissions shall meet the emission limit contained in paragraph (a) of this section during the time the saturator control device is operating. At any other time the asphalt storage tank(s) must meet the opacity limit specified above for storage tanks.

(d) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any mineral handling and storage facility

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emissions with opacity greater than 1 percent.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000]

§ 60.473 Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart, and using either an electrostatic precipitator or a high velocity air filter to meet the emission limit in § 60.472(a)(1) and/or (b)(1) shall continuously monitor and record the temperature of the gas at the inlet of the control device. The temperature monitoring instrument shall have an accuracy of $\pm 15^{\circ}\text{C}$ ($\pm 25^{\circ}\text{F}$) over its range.

(b) The owner or operator subject to the provisions of this subpart and using an afterburner to meet the emission limit in § 60.472(a)(1) and/or (b)(1) shall continuously monitor and record the temperature in the combustion zone of the afterburner. The monitoring instrument shall have an accuracy of $\pm 10^{\circ}\text{C}$ ($\pm 18^{\circ}\text{F}$) over its range.

(c) An owner or operator subject to the provisions of this subpart and using a control device not mentioned in paragraphs (a) or (b) of this section shall provide to the Administrator information describing the operation of the control device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may require continuous monitoring and will determine the process parameters to be monitored.

(d) The industry is exempted from the quarterly reports required under § 60.7(c). The owner/operator is required to record and report the operating temperature of the control device during the performance test and, as required by § 60.7(d), maintain a file of the temperature monitoring results for at least two years.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000]

§ 60.474 Test methods and procedures.

(a) For saturators, the owner or operator shall conduct performance tests required in § 60.8 as follows:

(1) If the final product is shingle or mineral-surfaced roll roofing, the tests

shall be conducted while 106.6-kg (235-lb) shingle is being produced.

(2) If the final product is saturated felt or smooth-surfaced roll roofing, the tests shall be conducted while 6.8-kg (15-lb) felt is being produced.

(3) If the final product is fiberglass shingle, the test shall be conducted while a nominal 100-kg (220-lb) shingle is being produced.

(b) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(c) The owner or operator shall determine compliance with the particulate matter standards in § 60.472 as follows:

(1) The emission rate (E) of particulate matter shall be computed for each run using the following equation:

$$E = (C_p Q_{ad}) / (PK)$$

where:

E = emission rate of particulate matter, kg/Mg (lb/ton).

C_p = concentration of particulate matter, g/dscm (gr/dscf).

Q_{ad} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

P = asphalt roofing production rate or asphalt charging rate, Mg/hr (ton/hr).

K = conversion factor, 1000 g/kg [7000 (gr/lb)].

(2) Method 5A shall be used to determine the particulate matter concentration (C_p) and volumetric flow rate (Q_{ad}) of the effluent gas. For a saturator, the sampling time and sample volume for each run shall be at least 120 minutes and 3.00 dscm (106 dscf), and for the blowing still, at least 90 minutes or the duration of the coating blow or non-coating blow, whichever is greater, and 2.25 dscm (79.4 dscf).

(3) For the saturator, the asphalt roofing production rate (P) for each run shall be determined as follows: The amount of asphalt roofing produced on the shingle or saturated felt process lines shall be obtained by direct measurement. The asphalt roofing production rate is the amount produced divided by the time taken for the run.

(4) For the blowing still, the asphalt charging rate (P) shall be computed for each run using the following equation:

$$P = (Vd) / (K' \theta)$$

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where:

P=asphalt charging rate to blowing still, Mg/hr (ton/hr).

V=volume of asphalt charged, m³ (ft³).

d=density of asphalt, kg/m³ (lb/ft³).

K=conversion factor, 1000 kg/Mg (2000 lb/ton).

θ=duration of test run, hr.

(i) The volume (V) of asphalt charged shall be measured by any means accurate to within 10 percent.

(ii) The density (d) of the asphalt shall be computed using the following equation:

$$d = K_1 - K_2 T_1$$

Where:

d = Density of the asphalt, kg/m³ (lb/ft³)

K₁ = 1056.1 kg/m³ (metric units)

= 64.70 lb/ft³ (English Units)

K₂ = 0.6176 kg/(m³ °C) (metric units)

= 0.0694 lb/(ft³ °F) (English Units)

T₁ = temperature at the start of the blow, °C (°F)

(5) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

(d) The Administrator will determine compliance with the standards in § 60.472(a)(3) by using Method 22, modified so that readings are recorded every 15 seconds for a period of consecutive observations during representative conditions (in accordance with § 60.8(c)) totaling 60 minutes. A performance test shall consist of one run.

(e) The owner or operator shall use the monitoring device in § 60.473 (a) or (b) to monitor and record continuously the temperature during the particulate matter run and shall report the results to the Administrator with the performance test results.

(f) If at a later date the owner or operator believes that the emission limits in § 60.472(a) and (b) are being met even though one of the conditions listed in this paragraph exist, he may submit a written request to the Administrator to repeat the performance test and procedure outlined in paragraph (c) of this section.

(1) The temperature measured in accordance with § 60.473(a) is exceeding that measured during the performance test.

(2) The temperature measured in accordance with § 60.473(b) is lower than

that measured during the performance test.

(g) If fuel oil is to be used to fire an afterburner used to control emissions from a blowing still, the owner or operator may petition the Administrator in accordance with § 60.11(e) of the General Provisions to establish an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. To obtain this opacity standard, the owner or operator must request the Administrator to determine opacity during an initial, or subsequent, performance test when fuel oil is used to fire the afterburner. Upon receipt of the results of the performance test, the Administrator will make a finding concerning compliance with the mass standard for the blowing still. If the Administrator finds that the facility was in compliance with the mass standard during the performance test but failed to meet the zero opacity standard, the Administrator will establish and promulgate in the FEDERAL REGISTER an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. When the afterburner is fired with natural gas, the zero percent opacity remains the applicable opacity standard.

[54 FR 6677, Feb. 14, 1989, as amended 54 FR 27016, June 27, 1989; 65 FR 61762, Oct. 17, 2000]

Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

SOURCE: 48 FR 48335, Oct. 18, 1983, unless otherwise noted.

§ 60.480 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction or modification

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Appendix I Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

**Registered
Federal Trade**

Friday
August 18, 1995

Part III

**Environmental
Protection Agency**

40 CFR Part 9, et al.
National Emission Standards for
Hazardous Air Pollutants: Petroleum
Refineries; Final Rule

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Part 9, 60 and 63**

[AD-FRL-5272-1]

RIN 2060-AD94

National Emission Standards for Hazardous Air Pollutants: Petroleum Refineries**AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Final rule.

SUMMARY: This final rule promulgates national emission standards for hazardous air pollutants (NESHAP) for petroleum refineries. This rule implements section 112 of the Clean Air Act (Act) and are based on the Administrator's determination that petroleum refineries emit organic hazardous air pollutants (HAPs) identified on the EPA's list of 189 HAPs. The health effects of exposure to HAPs can include cancer, respiratory irritation and damage to the nervous system. The petroleum refinery NESHAP requires petroleum refineries located at major sources to meet emission standards reflecting the application of the maximum achievable control technology (MACT), consistent with sections 112(d) and (h) of the Act. The petroleum refinery affected source is defined to include petroleum refinery process units, marine tank vessel loading operations, and gasoline loading rack operations classified under Standard Industrial Classification (SIC) code 2911 emission points located at petroleum refineries. The petroleum refinery affected source and source category description are revised to reflect the inclusion of these emission points. This action also amends two standards of performance for two stationary sources: Standards of performance for equipment leaks of volatile organic compounds (VOC) in the synthetic organic chemicals manufacturing industry (SOCMI); and standards of performance for VOC emissions from petroleum refinery wastewater systems. The amended standards were previously promulgated under section 111 of the Act.

EFFECTIVE DATE: August 18, 1995. See the Supplementary Information section concerning judicial review.

ADDRESSES: *Docket.* Docket No. A-93-48, containing information considered by the EPA in development of the promulgated standards, is available for public inspection between 8 a.m. and 4 p.m., Monday through Friday except for Federal holidays, at the following

address: U.S. Environmental Protection Agency, Air and Radiation Docket and Information Center (MC-6102), 401 M Street SW, Washington, DC 20460; telephone: (202) 260-7548. The docket is located at the above address in Room M-1500, Waterside Mall (ground floor). A reasonable fee may be charged for copying.

Response to Comment Document. The response to comment document for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone (919) 541-2777; or from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22151, telephone (703) 487-4650. Please refer to "National Emission Standards for Hazardous Air Pollutants, Petroleum Refineries-Background Information for Final Standards, Summary of Public Comments and Responses" (EPA No.-453/R-95-015b). The document contains: (1) A summary of all the public comments made on the proposed standards and the Administrator's response to the comments; and (2) a summary of the changes made to the standards since proposal. This document is also available for downloading from the Technology Transfer Network (see below) under the Clean Air Act, Recently Signed Rules.

Technology Transfer Network. The Technology Transfer Network is one of the EPA's electronic bulletin boards. The Technology Transfer Network provides information and technology exchange in various areas of air pollution control. The service is free except for the cost of a phone call. Dial (919) 541-5472 for up to a 14,400 bps modem. If more information on the Technology Transfer Network is needed call the HELP line at (919) 541-5384.

FOR FURTHER INFORMATION CONTACT: For information concerning the final standards, contact Mr. James Durham, Waste and Chemical Processes Group, Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 27711, telephone number (919) 541-5672.

SUPPLEMENTARY INFORMATION: *Judicial Review.* National emission standards for HAP's for petroleum refineries were proposed in the **Federal Register** (FR) on July 15, 1994 (59 FR 36130). This **Federal Register** action announces the EPA's final decisions on the rule. Under section 307(b)(1) of the Act, judicial review of the NESHAP is available only by the petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of

today's publication of this final rule. Under section 307(b)(2) of the Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by the EPA to enforce these requirements.

The following outline is provided to aid in reading the preamble to the final regulation.

- I. Background
- II. Summary of Considerations in Developing the Rule
 - A. Purpose of Regulation
 - B. Technical Basis of Regulation
 - C. Stakeholder and Public Participation
- III. Summary of Promulgated Standards
 - A. Miscellaneous Process Vent Provisions
 - B. Storage Vessel Provisions
 - C. Wastewater Provisions
 - D. Equipment Leak Provisions
 - E. Marine Vessel Loading and Unloading, Bulk Gasoline Terminal or Pipeline Breakout Station Storage Vessels, and Bulk Gasoline Terminal Loading Rack Provisions
 - F. Recordkeeping and Reporting Provisions
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- IV. Summary of Impacts
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 - A. Process Vents Group Determination
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- VI. Changes to NSPS
- VII. Administrative Requirements
 - A. Docket
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 - D. Regulatory Flexibility Act
 - E. Unfunded Mandates

I. Background

Section 112(b) of the Act lists 189 HAP's and directs the EPA to develop rules to control all major and some area sources emitting HAP's. On July 16, 1992 (57 FR 31576), the EPA published a list of major and area sources for which NESHAP are to be promulgated. Petroleum refineries were listed as a category of major sources. On December 3, 1993 (58 FR 83941), the EPA published a schedule for promulgating standards for the listed major and area sources. Standards for the petroleum refinery source category for sources not distinctly listed were scheduled for promulgation on November 15, 1994. The EPA is promulgating these standards under a July 28, 1995 court-ordered deadline.

II. Summary of Considerations in Developing the Rule

A. Purpose of Regulation

The Act was developed, in part,

To protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population (the Act, section 101(b)(1)).

Petroleum refineries are major sources of HAP emissions. Individual refineries emit over 23 megagrams per year (Mg/yr) (25 tons per year (tpy)) of organic HAP's including benzene, toluene, ethyl benzene, and other HAP's. The HAP's controlled by this rule are associated with a variety of adverse health effects. The range of adverse health effects include cancer and a number of other chronic health disorders (e.g., aplastic anemia, pancytopenia, pernicious anemia, pulmonary (lung) structural changes) and a number of acute health disorders (e.g., dyspnea (difficulty in breathing), upper respiratory tract irritation with cough, conjunctivitis, neurotoxic effects (e.g., visual blurring, tremors, delirium, unconsciousness, coma, convulsions). Table 1 presents the 11 most significant organic HAP's emitted from the petroleum refineries. Petroleum refineries also emit inorganic HAP's (e.g., hydrogen fluoride, hydrogen chloride). Inorganic HAP emissions from the emission points covered under this rule are low relative to organic HAP emissions. Emission points emitting inorganic HAP's are included in a separate source category under a separate schedule.

TABLE 1.—SIGNIFICANT HAZARDOUS AIR POLLUTANTS FROM PETROLEUM REFINERIES

[Hazardous Air Pollutant]	
2,2,4-Trimethylpentane	Methyl tert butyl ether.
Benzene	Naphthalene.
Cresols/cresylic acid	Phenol.
Ethylbenzene	Toluene.
Hexane	Xylenes.
Methyl ethyl ketone	

The catalytic cracking unit catalyst regeneration vent emits primarily metal HAP's, which would be controlled using particulate controls. Catalytic reformer catalyst regeneration vents emit hydrogen chloride, and sulfur plant vents emit carbonyl sulfide and carbon disulfide. Because of these compounds'

unique characteristics, the EPA concluded that these emission points warranted separate consideration for control of inorganic HAP's. Because limited data are currently available, these emission points are included in a separate source category under a separate schedule.

The Regulatory Impacts Analysis (RIA) presents the results of an examination of the potential health and welfare benefits associated with air emission reductions projected as a result of implementation of the petroleum refinery NESHAP. Of the pollutants emitted by petroleum refineries, some are classified as VOC, which are ozone precursors. Benefits from HAP emission reductions are presented separately from the benefits associated specifically with VOC emission reductions.

The predicted emissions of a few HAP's associated with this regulation have been classified as possible, probable, or known human carcinogens. Benzene and cresols are the two HAP's identified as carcinogens.

Benzene is classified as a class A or a known human carcinogen. Benzene is a concern to the EPA because long term exposure to this chemical causes an increased risk of cancer in humans, and is also associated with aplastic anemia, pancytopenia, chromosomal breakages, and weakening of the bone marrow.

Cresols are classified as class C or possible human carcinogens. For this HAP, there is either inadequate data or no data on human carcinogenicity. Therefore, while cancer risk is a possibility, there is not sufficient evidence to quantify the increased cancer risk to humans caused by these chemicals.

There are serious health effects reported from exposure to some of the noncarcinogenic HAP's. These serious health effects typically occur at higher levels of exposure than estimated for the regulatory baseline. Exposure to phenol is very toxic to animals and increases mortality, but there is little human data. Exposure to n-hexane can cause polyneuropathy (muscle weakness and numbness) in humans, and exposure to naphthalene is linked to cataracts and anemia in human infants. It is also possible that there are less serious health effects in the regulatory baseline from exposure to these HAP's.

Emissions of VOC have been associated with a variety of health and welfare impacts. Volatile organic compound emissions, together with nitrogen oxides (NO_x), are precursors to the formation of tropospheric ozone. Exposure to ambient ozone is responsible for a series of health

impacts, such as alterations in lung capacity; eye, nose, and throat irritation; malaise and nausea; and aggravation of existing respiratory disease. Among the welfare impacts from exposure to ambient ozone include damage to selected commercial timber species and economic losses for commercially valuable crops such as soybeans and cotton.

Based on existing data, the benefits associated with reduced HAP and VOC emissions were quantified. The quantification of dollar benefits for all benefit categories is not possible at this time because of limitations in both data and available methodologies. Although an estimate of the total reduction in HAP emissions for various regulatory alternatives has been developed for the RIA, it has not been possible to identify the specification of the HAP emission reductions for each type of emission point. However, an estimate of HAP speciation for equipment leaks has been made. Using emissions data for equipment leaks and the Human Exposure Model (version 1), the annual cancer risk caused by HAP emissions from petroleum refineries was estimated. Generally, this benefit category is calculated as the difference in estimated annual cancer incidence before and after implementation of each regulatory alternative. Since the annual cancer incidence associated with baseline conditions was less than one life per year, the cancer benefits associated with HAP reductions for the petroleum refinery NESHAP were determined to be low. Therefore, these quantified benefits are not part of the overall quantified benefits estimate for the analysis.

The benefits of reduced emissions of VOC from a MACT regulation of petroleum refineries were quantified using the technique of "benefits transfer." Because analysis by the Office of Technology Assessment from which benefits transfer values were obtained only estimated acute health benefits in ozone nonattainment areas, the transfer values can be applied to VOC reductions occurring only in ozone nonattainment areas. The range of benefit transfer values used in this analysis is from \$25 to \$1,574 per megagram (Mg) (\$23 to \$1,431 per ton) of VOC with an average of \$800/Mg (\$727/ton) of VOC.

In order to quantify benefits from VOC emission reductions, the average value is multiplied by VOC emission reductions from petroleum refineries in ozone nonattainment areas. Estimated annual benefits for VOC reductions are \$108.8 million for selected regulatory alternatives. The quantified annual

benefits exceed annual compliance costs by \$29.8 million (1992 dollars).

The promulgated NESHAP will reduce HAP emissions from petroleum refineries by 59 percent. Table 2

presents the national baseline emissions and emission reductions for petroleum refinery process vents, storage vessels, wastewater, and equipment leaks. The emissions reductions for controlling

gasoline loading racks and the marine vessel loading emission points are discussed in supporting material for the Gasoline Distribution (Stage I) and the Marine Vessel Loading Operations rules.

TABLE 2.—NATIONAL PRIMARY AIR POLLUTION IMPACT IN THE FIFTH YEAR

Source	Baseline emissions (Mg/yr)		Emission reductions			
	HAP	VOC	(Mg/yr)		(Percent)	
			HAP	VOC	HAP	VOC
Miscellaneous process vents	10,000	109,000	6,700	85,000	67	78
Equipment leaks	52,000	189,000	40,000	146,000	77	77
Storage vessels	9,300	111,000	1,300	21,000	14	19
Wastewater collection and treatment	10,000	10,000	(*)	(*)	(*)	(*)
Total	81,300	419,000	48,000	252,000	59	60

* The MACT level of control is no additional control.

B. Technical Basis of Regulation

National emission standards for major sources of HAP's established under section 112 of the Act reflect MACT or:

* * * the maximum degree of reduction in emissions of the HAP * * * that the Administrator, taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impacts and energy requirements, determine is achievable for new or existing sources in the category or subcategory to which such emission standard applies * * * (the Act section 112(d)(2)).

Prior to proposal, section 114 questionnaires, information collection requests (ICR's), and telephone surveys were used to obtain information on emissions, emissions control, and emissions control costs for petroleum refinery emission points. Section 114 questionnaires were sent out to nine large refineries, of approximately 130 existing petroleum refineries nationally, to obtain emissions and emissions control information for equipment leaks, wastewater, process vents, and storage vessel emission points located in a petroleum refinery. The ICR's were sent out to the refineries that were not sent section 114 questionnaires to obtain information on emissions control equipment and emissions for process vents, storage vessels, and equipment leaks emission points. A telephone survey of equipment vendors was conducted to obtain leak detection and repair (LDAR) cost information.

Data and information were received for approximately 130 petroleum refineries. This information was used, in part, as the technical basis in determining the MACT level of control for the process units covered under this rule. In addition to information collected from industry, the EPA used information on refinery locations and

processes available in the general literature. The EPA also used control technology performance and cost information developed under previous rulemakings for the petroleum and chemical industries, such as the petroleum refinery new source performance standard (NSPS), benzene NESHAP, and synthetic organic chemical manufacturing industry (SOCMI) standards. The EPA also considered existing State regulations and additional information received during the public comment period for the proposed rule in developing the final rule.

C. Stakeholder and Public Participation

In the development of this rule, numerous representatives of the petroleum refinery industry were consulted prior to proposal. Industry representatives have included trade associations, and refiners responding to section 114 questionnaires, ICR's, and telephone surveys. Representatives from State agencies and the EPA regions were also consulted and participated in the development of the rule.

The standards were proposed and published in the *Federal Register* on July 15, 1994 (59 FR 36130). The preamble to the proposed standard describes the rationale for the proposed rule. Public comments were solicited at the time of proposal.

To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was offered at proposal. A public hearing was held in Research Triangle Park, North Carolina, on August 5, 1994. The hearing was open to the public and four persons presented oral testimony. The public comment period was from July 15, 1994 to

September 13, 1994. Sixty-two comment letters were received. Commenters included industry representatives, States, environmental organizations, and others. The comments have been carefully considered, and changes have been made in the proposed standards when determined by the Administrator to be appropriate. A detailed discussion of these comments and responses can be found in the Response of Comment Document, which is referenced in the ADDRESSES section of this preamble. The summary of comments and responses in the document serve as the basis for the revisions that have been made to the standards between proposal and promulgation. Section V of this preamble discusses the major comments that resulted in changes to the standards.

III. Summary of Promulgated Standards

The promulgated standard applies to petroleum refining process units as well as other collocated emission points that are part of a plant site that is a major source as defined in section 112 of the Act. The determination of potential to emit, and therefore major source status, is based on the total of all HAP emissions from all activities at the plant site. The applicability section of the regulation specifies what is included in the petroleum refining source category and defines the sources regulated by the NESHAP.

The general standards consist of compliance dates for new and existing sources, require sources to be properly operated and maintained at all times, and clarify the applicability of the NESHAP General Provisions (40 Code of Federal Regulations (CFR) part 63, subpart A) to sources subject to subpart CC.

The affected source comprises the miscellaneous process vents, storage vessels, wastewater streams, and equipment leaks associated with petroleum refining process units, and marine tank vessel loading operations and gasoline loading racks classified under SIC code 2911 located at a refinery. The inclusion of marine tank vessel loading operations and gasoline loading racks in the definition of the petroleum refinery affected source and source category is a revision from the proposal. These emission points have been included as part of the petroleum refinery affected source and source category to permit an owner or operator of a petroleum refinery to average emissions among emission points collocated at the refinery to comply with the standards. These standards do not apply to distillation units located at pipeline pumping stations whose primary purpose is to produce fuel to operate turbines and internal combustion engines at the pipeline pumping stations. A summary of the specific provisions that apply to each of the emission points contained within a petroleum refinery affected source follows. All of the specified provisions for each of the covered emission points allow for, or are based on and encourage, pollution prevention.

These standards do not address three vents that will be subject to future NESHAP standards. These are the catalyst regeneration vents on catalytic cracking units and catalytic reforming units (CRU's) and vents from sulfur recovery units (SRU's). Industry is concerned that standards for these three vents will require the use of control technologies designed to reduce non-HAP emissions and will preclude the use of alternatives that can achieve comparable HAP control at a lower cost. The EPA recognizes that standards should be structured on a performance basis wherever possible to ensure that industry is provided the flexibility to seek out and implement cost-effective controls. The EPA's existing standards for sulfur dioxide and particulate matter emissions from new FCCU catalyst regenerator vents demonstrate such recognition. The allowable emissions were expressed in terms of the amount of coke burned off the catalyst in order to provide industry with the flexibility to comply through operational changes or through traditional end-of-pipe controls or a combination of the two. The EPA has every intention to ensure that future rules also provide similar flexibility.

A. Miscellaneous Process Vent Provisions

Miscellaneous process vents include vents from petroleum refining process units that emit organic HAP's. Vents that are routed to the refinery fuel gas system are considered to be part of the process and are not subject to the standard. The miscellaneous process vent provisions define two groups of vents. Group 1 process vents are those with VOC emissions greater than or equal to 33 kilograms per day (kg/day) (72 pounds per day (lb/day)) for existing sources and 6.8 kg/day (15 lb/day) for new sources. Group 2 vents are vents with emissions below these levels.

The miscellaneous process vent provisions for new and existing sources require the owner or operator of a Group 1 miscellaneous process vent to reduce organic HAP emissions by 98 percent or to less than 20 parts per million by volume (ppmv), or to reduce emissions using a flare meeting the requirements of § 63.11(b) of the NESHAP General Provisions (40 CFR part 63, subpart A).

Monitoring requirements for Group 1 vents include an initial performance demonstration and monitoring of control device operating parameters. The owner could also comply by reducing emissions from a Group 1 process vent to less than 33 kg/day (72 lb/day) for existing sources and 6.8 kg/day (15 lb/day) for new sources, thereby converting it to a Group 2 process vent. No controls or monitoring are required for Group 2 process vents.

B. Storage Vessel Provisions

The storage vessel provisions define two groups of vessels: Group 1 vessels are vessels with a design storage capacity and a maximum true vapor pressure above the values specified in the regulation. Group 2 vessels are all storage vessels that are not Group 1 vessels. The storage vessel provisions require that one of the following control systems be applied to Group 1 storage vessels: (1) An internal floating roof (IFR) with proper seals; (2) an external floating roof (EFR) with proper seals; (3) an EFR converted to an IFR with proper seals; or (4) a closed vent system to a control device that reduces HAP emissions by 95 percent or to 20 ppmv. The storage provisions give details on the type of seals required. Monitoring and compliance provisions for Group 1 vessels include periodic external visual inspections of vessels and roof seals, as well as less frequent internal inspections. If a closed vent system and control device is used for venting emissions from Group 1 storage vessels, the owner or operator must establish

appropriate monitoring procedures. No controls or inspections are required for Group 2 storage vessels.

For existing sources, the final rule requires that fixed roof tanks with capacities greater than or equal to 177 cubic meters (m³) (47,000 gallons (gal)) that store liquids containing more than 4 percent organic HAP with vapor pressures greater than 10.4 kilopascals (kPa) (1.5 pounds per square inch absolute (psia)) comply fully with the rule within 3 years. If an owner or operator must replace an existing fixed roof tank in order to comply with the rule, it would be reasonable for the State to grant an additional year to comply as authorized under section 112(i)(3)(B) of the Act (a total of four years). This additional time would allow time to design and construct tanks without disrupting refinery operations that could create additional emissions. Owners or operators of IFR or EFR tanks are allowed to defer upgrading of their seals to meet the NESHAP requirements until the next scheduled inspection and maintenance activity or within 10 years, whichever comes first.

For new sources, the final rule requires that vessels with capacities greater than or equal to 151 m³ (40,000 gal), that store liquids containing more than 2 percent organic HAP with vapor pressures equal to or greater than 3.4 kPa (0.5 psia), and vessels with capacities equal to or greater than 76 m³ (20,000 gal) storing liquids containing more than 2 percent organic HAP with vapor pressures equal to or greater than 77 kPa (11.1 psia) comply with the level of control required by 40 CFR part 63, subpart G (including the controlled fitting requirements).

C. Wastewater Provisions

The wastewater provisions define two groups of wastewater streams. Group 1 streams are those that are located at a refinery with a total annual benzene loading of at least 10 megagrams per year (Mg/yr) (11 tpy) and are not exempt from control requirements under 40 CFR part 61, subpart FF (the benzene waste operations NESHAP or BWON). In general, streams are not exempt from 40 CFR part 61 subpart FF if they contain a concentration of at least 10 parts per million by weight (ppmw) benzene, and have a flow rate of at least 0.02 liters per minute (L/min) (0.005 gallons per minute (gal/min)). Group 2 streams are wastewater streams that are not Group 1.

The wastewater provisions of the final rule refer to the BWON for both new and existing sources, which requires owners or operators of a Group 1 wastewater stream to reduce benzene

mass emissions by 99 percent using suppression followed by steam stripping, biotreatment, or other treatment processes. Vents from steam strippers and other waste management or treatment units are required to be controlled by a control device achieving 95 percent emissions reduction or 20 ppmv at the outlet of the control device. The performance tests, monitoring, reporting, and recordkeeping provisions required to demonstrate compliance are included in the BWON. No controls or monitoring are required for Group 2 wastewater streams.

D. Equipment Leak Provisions

The equipment leak standards for the petroleum refinery NESHAP allow owners or operators of existing sources to choose between complying with equipment leaks provisions in 40 CFR part 60, subpart VV (NSPS for Equipment Leaks) or complying with a modified negotiated regulation for equipment leaks presented in 40 CFR part 63, subpart H (Hazardous Organic NESHAP or HON equipment leaks). The differences in the NSPS equipment leak requirements and the HON equipment leak requirements are in the leak definitions and connector monitoring provisions.

Under either of the two options, existing refineries subject to the rule will be required to implement a LDAR program with the same leak definitions (10,000 parts per million (ppm)) and frequencies as specified in 40 CFR part 60, subpart VV within 3 years after promulgation of the petroleum refineries NESHAP. Refineries that choose to comply with the modified negotiated regulation would implement the Phase II leak definitions and frequencies at the end of the fourth year, and comply with Phase III requirements 5½ years after promulgation. Phase III defines a leak at a lower level, but allows less frequent monitoring for good performers. Although the modified negotiated regulation is not required in the final rule, the EPA believes that it

would provide greater emission reductions and, in many cases, would be more cost effective than 40 CFR part 60, subpart VV and could even provide cost savings. Cost savings would occur because it would reduce equipment leak product loss, and facilities with a low percentage of leaking valves would be able to monitor less frequently, thereby reducing monitoring costs.

New sources must comply at startup with the modified negotiated regulation; pumps and valves at new sources must be in compliance with the Phase II requirements at startup rather than Phase I. This is consistent with the negotiated rule (40 CFR part 63, subpart H).

E. Marine Tank Vessel Loading and Gasoline Loading Rack Provisions

The final refineries NESHAP requires marine tank vessel loading operations at refineries to comply with the marine loading NESHAP (40 CFR part 63, subpart Y) unless they are included in an emissions average. Gasoline loading racks classified under SIC code 2911 at refineries are required to comply with the 40 CFR part 63, subpart R loading rack provisions unless they are included in an emissions average.

F. Recordkeeping and Reporting Provisions

The final rule requires that petroleum refineries subject to 40 CFR part 63, subpart CC maintain required records for a period of at least 5 years. The final rule requires that the following reports be submitted: (1) A Notification of compliance status report, (2) periodic reports, and (3) other reports (e.g., notifications of storage vessel internal inspections; startup, shutdown, and malfunction reports).

G. Emissions Averaging

The EPA is allowing emissions averaging among existing miscellaneous process vents, storage vessels, wastewater streams, marine tank vessel loading operations, and gasoline loading racks classified under SIC code 2911

located at a refinery. New sources are not allowed to use emissions averaging. Under emissions averaging, a system of emission "credits" and "debits" is allowed to determine whether a source is achieving the required emission reductions.

IV. Summary of Impacts

The impacts presented in this section include process vents, storage vessels, equipment leaks, and wastewater streams from petroleum refinery process units. Impacts for control of marine tank vessel loading operations and gasoline loading rack operations classified under SIC code 2911 located at refineries are presented in the background documentation for 40 CFR part 63, subparts Y and R.

These standards will reduce nationwide emissions of HAP from petroleum refineries by 48,000 Mg/yr (53,000 tpy), or 59 percent by 1998 compared to the emissions that would result in the absence of standards. No adverse secondary air impacts, water or solid waste impacts are anticipated from the promulgation of these standards.

The national electric usage required to comply with the rule is expected to increase by 48 million kilowatt-hours per year, which is equivalent to approximately 77,500 barrels of oil.

The implementation of this regulation is expected to result in an overall annual national cost of \$79 million. This includes a cost of \$59 million from operation of control devices, and a monitoring, recordkeeping, and reporting cost of \$20 million. The monitoring, reporting, and recordkeeping cost has been reduced by 25 percent from proposal. Table 3 presents the national control cost impacts for petroleum refinery process vents, storage vessels, wastewater, and equipment leaks. The control costs for gasoline loading racks and marine tank vessel loading operations are discussed in supporting material for the Gasoline Distribution (Stage I) and the Marine Vessel Loading Operations rules.

TABLE 3.—NATIONAL CONTROL COST IMPACTS IN THE FIFTH YEAR

Source	Total ^a capital costs ^b (\$10 ⁶)	Total ^a annual costs (\$10 ⁶ /yr)	Average HAP cost effectiveness (\$/Mg HAP)	Average VOC cost effectiveness (\$/Mg VOC)
Miscellaneous process vents	21 (2)	12 (1)	1,800	140
Equipment leaks	142 (16)	58 (17)	1,500	400
Storage vessels	48 (1)	8 (1)	6,100	380
Wastewater collection and treatment	(c)	(c)	(c)	(c)
Other recordkeeping and reporting	2	1	(d)	(d)

TABLE 3.—NATIONAL CONTROL COST IMPACTS IN THE FIFTH YEAR—Continued

Source	Total ^a capital costs ^b (\$10 ⁶)	Total ^a annual costs (\$10 ⁶ /yr)	Average HAP cost effectiveness (\$/Mg HAP)	Average VOC cost effectiveness (\$/Mg VOC)
Total	213 (21)	79 (20)	1,600	310

^a Numbers in parentheses are recordkeeping and reporting costs included in total annual cost and total capital cost estimates. For equipment leaks, activities associated with setting up and operating a LDAR program (e.g., tagging and identifying, monitoring, data entry, setting up a data management system, etc.) are not reflected in the equipment leak recordkeeping and reporting costs, but are included in the equipment leak total annual cost and total capital cost estimate.

^b Total capital costs incurred in the 5-year period.

^c The MACT level of control is no additional control.

^d Not applicable.

The EPA estimates that changes in the compliance times for storage vessels with floating roofs and changes to the process vents Group 1 applicability cutoff will provide substantial cost savings and emissions reductions for refineries. Estimates of degassing and cleaning storage tank costs provided by the refining industry indicate that premature (within 3 years of promulgation) degassing and cleaning activities would cost between \$34,000 and \$213,000 per floating roof tank depending on the type of material stored. If extrapolated to the entire refining industry for floating roof tanks, the cost savings from allowing floating roofs to comply at the next scheduled maintenance would be \$6.6 million per year.

The EPA determined that substantial HAP emissions occur when storage vessels are degassed and cleaned. Typically, storage vessels are inspected and maintained on a 10-year schedule, at which time tanks are degassed and cleaned. If a 3-year compliance schedule were required, storage vessels would be degassed and cleaned prematurely, resulting in substantial HAP emissions caused by the rule. These HAP emissions could not be balanced in less than 5 years for floating roof tanks by the emission reduction achieved from complying with the rule. By changing the proposed rule to allow floating roof tanks to comply with the storage vessel requirements 10 years after promulgation of the rule or at the next scheduled inspection, the EPA estimates that 3,000 Mg/yr (2,700 tpy) of HAP, or 8,000 Mg (7,200 tpy) of HAP over 3 years, would be prevented from being emitted.

The existing source process vent applicability cutoff (33 kg of VOC/day (72 lb of VOC/day) per vent) will exclude 3,000 vents from requiring control at a total annual cost savings of \$4.5 million. The new source process vent applicability cutoff (7 kg of VOC/day (15 lb of VOC/day) per vent) will exclude 35 vents from requiring control

at a total annual cost savings of \$25,000. The total annual cost reduction of these changes in the rule is a reduction of approximately \$11 million.

The economic impact analysis for the selected regulatory alternatives shows that the estimated price increases for affected products range from 0.24 percent for residual fuel oil to 0.53 percent for jet fuel. Estimated decreases in product output range from 0.13 percent for jet fuel to 0.50 percent for residual fuel oil. Annual net exports (exports minus imports) are predicted to decrease by 2.3 million barrels, with the range of reductions varying from 0.21 million barrels for liquid petroleum gas to 0.91 million barrels for residual fuel oil.

Between zero and seven refineries, all of which are classified as small, may close due to the regulation. For more information, consult the "Economic Impact Analysis for the Petroleum Refinery NESHAP" in the docket (see ADDRESSES section of this preamble).

V. Significant Comments and Changes to the Proposed Standards

In response to comments received on the proposed standards, several changes have been made to the final rule. While several of these changes are clarifications designed to make the Agency's intent clearer, a number of them are significant changes to the proposed standard requirements. A summary of the substantive comments and/or changes made since the proposal are described in the following sections. Detailed Agency responses to public comments and the revised analysis for the final rule are contained in the BID and docket (see ADDRESSES section of this preamble).

A. Process Vents Group Determination

The proposed NESHAP would have required control of all miscellaneous process vents with HAP concentrations over 20 ppmv. This level was based on the fact that combustion control technologies can reduce organic emissions by 98 percent or to 20 ppmv,

but cannot necessarily achieve lower concentrations. Several commenters suggested that other applicability criteria were needed to determine which process vents are required to apply control. They pointed out that the HON and State regulations use a total resource effectiveness (TRE) or emission rate cutoff to exclude small vents that have low emission potential and high costs from control requirements. The commenters contended that the MACT floor does not include control of such vents.

In response to these comments, the EPA examined potential control applicability criteria. The EPA reevaluated the miscellaneous process vents data base. The EPA's information on miscellaneous process vent streams was insufficient to establish an emission rate cutoff. This was because industry did not have sufficient information on the HAP and VOC content of vent streams requested by the section 114 questionnaires and ICR's and it would have been impractical to obtain this information. Therefore, as suggested by a number of commenters, and after consultations with industry and others, the EPA decided to use State regulations.

The EPA evaluated the current level of control for miscellaneous process vents in eight States and two air districts that contain the majority of refineries and were expected to have the most stringent regulations. Of the refineries in the United States, the 12 percent that are subject to the most stringent regulations are located in three States. In these three States, miscellaneous process vents emitting greater than 6.8 to 45 kg/day (15 to 100 lb/day) of VOC are required to be controlled. The median applicability cutoff level for the 12 percent of U.S. refineries subject to the most stringent regulations is 33 kg/day (72 lb/day VOC). Thus, control of vents with VOC emissions greater than 33 kg/day (72 lb/day) is the MACT floor for existing sources and 6.8 kg/day (15 lb/day) is the

MACT floor level of control for new sources. The primary organic HAP's at refineries are also VOC. Additionally, a VOC-based applicability criteria is most reflective of the current level of control required for miscellaneous process vents as the majority of State regulations are expressed in terms of VOC. Therefore, the EPA has adopted these emission levels in the final rule to distinguish Group 1 from Group 2 vents. Group 1 vents are those that emit over 33 kg/day (72 lb/day) for existing sources and over 6.8 kg/day (15 lb/day) for new sources. Group 1 vents must be controlled, whereas Group 2 vents (which emit less than 33 kg/day (72 lb/day) for existing sources and less than 6.8 kg/day (15 lb/day) for new sources) are not required to apply controls under the final rule. The 33 kg/day (72 lb/day) and 6.8 kg/day (15 lb/day) applicability limits are to be determined as the gases exit from process unit equipment (including any recovery devices) and prior to any non-recovery emission control device.

B. Process Vent Impacts

At proposal, the EPA estimated that the baseline HAP and VOC emissions from process vents were 9,800 Mg/yr (10,780 tpy) and 190,000 Mg/yr (209,000 tpy), respectively. Several commenters contended that the impacts analysis for process vents should be redone because: (1) The data base used in the analysis contained several errors, and (2) the emission estimation methodology was incorrect. The commenters asserted that these inaccuracies resulted in overestimates of emissions. Some of the commenters asserted that the data base flaws included: (1) A lack of data concerning the number, flowrates, and HAP concentrations of miscellaneous process vents, and (2) an erroneously high percentage of controlled vents because many uncontrolled vents were not reported. Some of the commenters contended that the emission estimation methodology was flawed because (1) It included wastewater and maintenance emissions, (2) emission factors were calculated from a HAP-to-VOC ratio that included reformer emissions, and (3) alkylation emissions and crude unit emissions were based on one refinery where vents were uncontrolled at the time of the questionnaire and are now controlled.

The EPA agrees with the commenters that the process vents emission impacts estimate has several assumptions that needed to be reanalyzed. The EPA also agrees that the data base used at proposal should be reevaluated to consider the commenters' concerns. Therefore, the EPA has reestimated the

emissions and cost impacts of the process vents provisions using the commenters' recommendations.

The emissions at proposal were estimated using responses from only the section 114 questionnaires extrapolated to the entire refining industry. Because the section 114 questionnaires were sent to the largest companies, the data obtained from them skewed the results based on what the largest refineries did. The revised emissions were estimated using data from both the section 114 and ICR responses. The ICR questionnaires were sent to refineries not receiving the section 114 questionnaires. This additional data increased the number of vents in the data base by 1,300. The increase in vents resulted in a decrease in controlled vents from 40 percent to 24 percent. However, information on the HAP and VOC content of vent streams remained limited as no new data was provided by the ICR respondents. Additionally, no new HAP information was provided by industry after proposal of the rule.

Additionally, errors in the data base were corrected and non-miscellaneous process vents were removed from the data base (e.g., vents from wastewater, maintenance, catalytic reformer regeneration vents, etc). In the revised emission estimates, emissions from alkylation and crude units were estimated from a number of different data points (not just one, as the commenters have stated). Additionally, the one data point the commenters have referred to has been changed to reflect the change in control status. The revised baseline miscellaneous process vents HAP and VOC emissions are 10,000 Mg/yr (11,000 tpy) and 109,000 Mg/yr (119,900 tpy), respectively.

The EPA agrees that the data on HAP concentrations is limited. However, no new data was supplied by the commenters. The EPA's revised emission estimates are based on technically sound methods and the best available information.

C. Equipment Leaks Compliance Requirements

The proposed rule for equipment leaks at existing sources was an above-the-floor option modeled after the HON negotiated rule for equipment leaks. The floor level of control for equipment leaks from existing sources was determined to be control equal to the petroleum refinery NSPS. The modified negotiated rule was chosen as an above-the-floor option because it was estimated to be cost effective. The option chosen in the proposed rule differed from the HON in that: (1)

Existing sources were not required to monitor connectors, and (2) the leak definitions were higher to reflect the different volatility of materials found in refinery process lines as opposed to SOCM process lines. The proposed rule required one-third of the refinery to be in compliance 6 months after promulgation of the rule, two-thirds of the refinery to be in compliance 1 year after promulgation of the rule, and the entire refinery to be in compliance 18 months after promulgation of the rule.

Several commenters contended that the emissions and cost information used to determine the cost effectiveness of going from the floor level of control to the modified negotiated rule were inaccurate and did not consider recent changes to the equipment leak correlation equations for petroleum refineries. The commenters concluded that using the most recent information for refineries would show that it is not cost effective to go beyond the floor level of control.

The cost information used in the analysis was the best data available, and is based on surveys of vendors and established costs presented in previous projects. No new cost information was submitted by the industry. The equipment leak emission factors that are being used to estimate the emissions and emission reductions of the rule were developed in 1980. These are the only complete and accurate emission factors available for this purpose. To accurately estimate emissions from equipment leaks, two sets of information are needed. These include the amount of emissions generated per piece of equipment leaking at a given concentration and the percent of equipment that are actually leaking at these concentrations. The 1980 study that was used to estimate the impacts of the refinery MACT rule used a consistent sampling methodology to address both of these factors based on sampling at uncontrolled refineries. The 1993 API study developed new information only on emissions per piece of leaking equipment using a different methodology. As stated in API's report, this information was developed from refineries in California for use with other information to estimate facility-specific equipment leak emissions. Thus, this study was not designed to provide information on industry average percent leaking equipment. Therefore, it was not possible to redefine average emission factors. To actually use this information, however, the EPA would need corresponding new information on the percent of equipment leaking. The EPA does not believe that it would be appropriate to combine 1993

information with the 1980 data to develop new emission factors because sampling methodologies were different and because the 1993 study collected information from information from well-controlled facilities while the 1980 study collected information from uncontrolled facilities. However, the EPA agrees that new correlation equations developed for the refining industry indicate that the refinery factors may overestimate emissions by as much as a factor of two, which may make the modified negotiated rule option less cost effective. This cannot be accurately determined because the appropriate information to update average emission factors is not available. The EPA recognizes that enough uncertainty exists in the emission and cost estimates to question the results of the cost-effectiveness analysis.

In recognition of this uncertainty and to provide compliance flexibility, the EPA has changed the final rule to provide each existing refinery with a choice of complying with either: (1) The equipment leaks NSPS requirements (40 CFR part 60, subpart VV) or (2) a modified version of the negotiated rule (40 CFR part 63, subpart H). The NSPS represents the MACT floor for existing sources. The modified negotiated regulation is the same as what was contained in the proposed petroleum refinery NESHAP except that the compliance dates have been extended for reasons described below. Although not required in the final rule, the EPA promotes use of the modified negotiated rule option because it is believed to provide considerable product, emissions, and cost savings to a refinery.

Under either option, existing refineries will be required to implement an LDAR program with the same leak definitions (10,000 ppm) and the same leak frequencies as contained in the NSPS by 3 years after promulgation. A refinery may opt to remain at this level of control and do the monitoring, recordkeeping, and reporting specified in the NSPS. This option allows refineries that are familiar with the NSPS to continue to implement that standard without needing to change their procedures.

Alternatively, a refinery may choose to comply with Phase I of the negotiated rule (10,000 ppm leak definition) 3 years after promulgation, comply with Phase II 4 years after promulgation, and comply with Phase III 5½ years after promulgation. Each phase has lower leak definitions for pumps and valves. In Phase III, monitoring frequencies for valves are dependent on performance (percent leakers), providing an incentive

(less frequent monitoring and reduced monitoring costs) for good performance. Refineries choosing to comply with the modified negotiated rule are subject to monitoring, recordkeeping, and reporting requirements of subpart H. The EPA has included this compliance alternative to add flexibility and opportunities for adjustment for differences among facilities.

The compliance dates for equipment leaks were revised to address commenter concerns that contended that small refineries and refineries in ozone attainment areas would be at a disadvantage if they were required to comply with the proposed equipment leak regulations because they would not have the experience to implement an equipment leaks control program within 6 to 18 months.

The EPA agrees that small refineries may not have the experience to implement an LDAR program for equipment leaks in a short timeframe without significant expense. The EPA also contends that other refineries that do not currently have LDAR programs may also have trouble implementing the rule in 6 to 18 months. In response to these comments, the EPA has changed the final rule to require that existing refineries, regardless of size, comply with an LDAR program with the same leak definitions (10,000 ppm) and monitoring frequencies as the petroleum refinery NSPS within 3 years of promulgation of the rule. At the end of the third year, the entire refinery must be in compliance with the petroleum refinery NSPS level of control; there will not be interim deadlines during the 3-year period by which portions of the refinery are required to comply during this time. A refinery owner or operator who chooses to comply with the modified negotiated rule must then implement Phase II within 4 years and Phase III within 5½ years of promulgation. The total annual cost estimates for the rule have been revised in accordance with the changes made to the equipment leak requirements.

D. Storage Vessels

The proposed rule required existing storage vessels containing liquids with vapor pressures greater than or equal to 8 kPa (1.2 psia) to comply with storage vessel requirements within 3 years. For tanks that were already controlled with internal or external floating roofs, the proposed rule allowed operators to defer upgrading of seals until the next scheduled maintenance with the following exceptions: (1) Fixed roof tanks, (2) EFR tanks with only a vapor-mounted primary seal, and (3) all tanks

storing a liquid with a true vapor pressure greater than 34 kPa (5.0 psia).

Commenters to the proposed rule maintained that before additional emission controls (e.g., secondary seals) can be installed, tanks must be removed from service, degassed, and cleaned. Storage tanks are currently emptied and cleaned roughly every 10 years for inspection and maintenance. The commenters contended that removing storage tanks that already have floating roofs from service before scheduled maintenance would have adverse environmental impacts that could not be overcome by the emissions reductions from upgrading the seals on the tank. The commenters further stated that tank owners or operators would incur substantial costs as a result of degassing and cleaning a tank before scheduled maintenance. The commenters contended that a 3-year compliance schedule could not be met because there would not be enough trained and capable fabricators and contractors to support the tank modification work. Commenters stated that the reason was that the refinery rule compliance period overlaps with the implementation of other EPA rules and that a 10-year compliance schedule would be consistent with other EPA rulemakings such as the HON and the benzene storage NESHAP.

The EPA agrees with the commenters that the HON and the benzene storage NESHAP allow floating roof tanks to achieve compliance in 10 years or at the time of the next scheduled degassing. Most existing floating roof storage vessels at refineries also fall under the 10-year compliance schedule. Therefore, these storage vessels will be inspected within 5 to 10 years after promulgation of the rule. This is consistent with industry practice.

In response to these comments, the EPA analyzed the emissions resulting from degassing and cleaning storage vessels using empirical mass-transfer models. The analysis indicated that degassing and cleaning of floating roof vessels generally results in substantial volatilization of HAP's to the air. These emissions could not be balanced in less than 5 years by the emission reductions achieved by controlling the tank to the requirements in the rule. Additionally, the degassing and cleaning information submitted by the refining industry indicated substantial costs for each degassing and cleaning activity if required within 3 years after promulgation of the rule. Based on information provided by industry and the EPA's empirical analysis, the EPA determined that the proposed storage vessel provisions would, in many cases,

result in increased overall emissions because of the extra degassing emissions.

The final rule allows owners or operators of storage vessels subject to the rule to defer installation of better seals on floating roof tanks storing any liquid until the next scheduled maintenance or within 10 years, whichever comes first. This change addresses the commenters' concerns about emissions and costs as well as their concern about the availability of trained fabricators and contractors to modify the tanks within a 3-year period. The final rule maintains the requirement to retrofit IFR tanks at existing sources with secondary seals that meet 40 CFR part 60 subpart Kb requirements because it is the MACT floor for IFR vessels.

Based on the EPA's analysis, the emissions from degassing and cleaning fixed roof tanks can be balanced within 1 year (justifying a 3-year compliance date) by the emission reductions achieved by controlling the tank to the requirements in the rule. Therefore, the final rule maintains the proposed compliance times (within 3 years) for fixed roof tanks. The EPA believes that in certain situations, such as when replacement of a tank is required, it would be reasonable for States to grant an additional year to comply as authorized under section 112(i)(3)(B) of the Act. The additional year would provide time to design and construct the tanks without disrupting refinery operations which could cause additional emissions. The EPA will work with the industry and States to find ways to use the emissions averaging program to deal with cases where tanks have to be replaced or where it is extremely difficult or costly to install the required controls.

Several commenters contended that the Group 1 definition of 8 kPa (1.2 psia) in the proposed NESHAP was based on data requests in section 114 and ICR questionnaires that were misinterpreted by respondents. The commenters stated that the questionnaires did not specify whether respondents were to provide maximum true vapor pressures or average annual true vapor pressures. The commenters elaborated that because other data were provided to estimate emissions on an annual basis, it was reasonable to assume that respondents provided average annual true vapor pressures instead of maximum true vapor pressures. The commenters concluded that vapor pressures based on the maximum monthly temperatures may be 0.3 psia higher than the average annual true vapor pressure. The commenters

recommended that the EPA either change the applicability cutoff to 10 kPa (1.5 psia) maximum true vapor pressure to account for this difference or specify that the 8 kPa (1.2 psia) cutoff is the average annual true vapor pressure instead of the maximum true vapor pressure.

The EPA agrees with the commenters that because the questionnaires did not specify the type of vapor pressure, the respondents may have provided annual average true vapor pressures instead of maximum true vapor pressures. In order to reflect the uncertainty of the type of vapor pressure provided in the questionnaires, the EPA has decided to change the storage vessel applicability cutoff in the final rule from a maximum true vapor pressure of 8 kPa (1.2 psia) to 10 kPa (1.5 psia). An analysis of the storage vessel data base indicated that a change from 8.3 kPa (1.2 psia) to 10 kPa (1.5 psia) will not affect the impacts analysis.

Several commenters requested that a minimum HAP content be considered as well as a vapor pressure cut-off for storage vessels because some liquids may have very low HAP concentrations and high vapor pressures due to the volatility of non-HAP compounds in the material. The EPA agrees that several products, such as asphalt, have minimal HAP's that may have vapor pressures greater than 10 kPa (1.5 psia) if stored at elevated temperatures. To determine HAP weight percent applicability criteria, the EPA reviewed the MACT floor analysis for storage vessels to determine the HAP weight percents in controlled storage vessels at the best-controlled sources. The MACT floor for new sources is based on the best-controlled source, while the floor for existing sources is the average of the best-controlled 12 percent of sources (or 16 refineries). The HAP weight percent applicability criterion was determined using the same population of storage tanks used to determine the vapor pressure applicability cut-off (i.e., the best-controlled 16 refineries). The minimum HAP concentrations for materials stored in the tanks meeting subpart Kb at the 16 best-controlled sources ranged from 2 weight percent to 22 weight percent. The average HAP weight percent in the liquids stored in these tanks is 4 percent. The best-controlled tanks contain liquids with a HAP weight percent in the liquid of 2 percent. Therefore, the HAP weight percent criterion for existing sources is 4 percent HAP in the liquid; the HAP weight percent for new sources is 2 percent HAP in the liquid.

E. Overlapping Regulations

Several commenters contended that the petroleum refinery NESHAP will lead to overlap with other existing and future regulations such as the 40 CFR part 60 NSPS, 40 CFR parts 61 and 63 NESHAP, and State and local regulations. Commenters stated that the overlap between regulations will lead to confusion, uncertainty, and frustration for sources and regulators.

The EPA has clarified the applicability of subpart CC as it relates to other NSPS and parts 61 and 63 NESHAP that apply to the same source in § 63.640 of the final rule.

The final rule clarifies the applicability of 40 CFR part 63, subpart CC storage vessel provisions to storage vessels at existing and new petroleum refinery sources subject to 40 CFR part 60, subparts K, Ka, or Kb. The specific provisions are structured such that each vessel is subject to only the more stringent rule. For example, a Group 1 storage vessel at an existing refinery that is also subject to subpart K or Ka is required only to comply with the petroleum refinery NESHAP storage vessel provisions.

The final rule clarifies the applicability of 40 CFR part 63, subpart CC wastewater provisions by stating that a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required only to comply with 40 CFR part 63, subpart CC. The final rule also clarifies that a Group 2 wastewater stream managed in equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required only to comply with subpart QQQ. Clarification of the applicable provisions for a wastewater stream that is conveyed, stored, or treated in a wastewater stream management unit that also receives streams subject to the provisions of 40 CFR part 63, subpart F has been included in the final rule.

There should not be any process vent applicability overlap between subpart CC and any other Federal rule. Process vents regulated under the HON are not subject to the petroleum refinery NESHAP.

The EPA clarifies the applicability of subpart CC equipment leak provisions in the final rule by stating that petroleum refinery sources subject to subpart CC and 40 CFR parts 60 or 61 equipment leaks regulations are required to comply only with the petroleum refinery NESHAP (40 CFR part 63, subpart CC) equipment leak provisions.

The EPA has also included a Standard Industrial Classification (SIC) code definition for petroleum refining (2911) to the petroleum refinery process units definition in the final rule in order to clarify which provisions of the rule apply to storage vessels and equipment leaks. The EPA believes that the inclusion of the SIC code reference in the definition of refinery process unit will alleviate confusion about applicability of this rule (reducing potential confusion regarding process unit regulatory overlap) and other source categories scheduled for the development of NESHAP under the Act. The EPA has also added a list of pollutants covered under the rule to assist facilities in the determination of whether emission points are covered under the rule.

Another issue raised by several commenters was the potential for overlap between the petroleum refinery MACT and other MACT standards such as the HON. These commenters requested that the EPA clarify the distinction between process units subject to the HON or other MACT standards and process units subject to the petroleum refinery MACT standard. These commenters thought that the description of refinery process units was too general and could include chemical processes subject to the HON or other MACT standards.

The final rule provides that 40 CFR part 63, subpart CC does not apply to units that are also subject to the provisions of the HON. The applicability of subpart CC versus the HON or other MACT standard to an emission point is determined by the primary product produced in the unit. The primary product is the product that is produced in the greatest mass or volume that the unit produces. For example, if a refinery operates a unit that produces upgraded feedstock for the alkylation unit and this unit also produces a small quantity (less than 20 percent) of the chemical methyl tert butyl ether (MTBE), that unit is considered to be subject to the petroleum refinery MACT standard and not to the HON. In contrast, if a facility operated a process unit that produced MTBE as the primary product and also produced small quantities of a mixed hydrocarbon stream, the unit would be subject to the HON because the unit produces MTBE as the primary product and the HON applies to chemical manufacturing units that produce MTBE. The distinction between the units is the difference in the primary product produced in the different units. In the first case, the unit is integral to the petroleum refinery's operations and

the MTBE is a by-product of the unit. In the second case, the unit's operation could be replaced by purchased MTBE and the operation is not integral to the petroleum refinery's operations.

The EPA believes that including the concept of primary use in the petroleum refining process unit definition clarifies the applicability of the petroleum refinery MACT standard, and that including the primary product concept in HON and other MACT standards will avoid the same emission point from the same process unit being subject to multiple MACT standards. The EPA also believes that by directly stating in the rule that process units subject to the HON are not subject to this rule, the commenter's concerns over applicability issues have been addressed.

F. Source Category Definition

In the July 1994 notice of proposed rulemaking, the proposed rule preamble provided notice of and sought comment on the issues of a broad affected source definition and source category; source-wide averaging; and the relationship between the gasoline distribution affected source definition and source category and refineries. In the preamble of the proposed refinery rule, the EPA noted that it did not intend to include emission points that are subject to the gasoline distribution standard in the refinery source category, that all emission points within the refinery source category would be treated as one stationary source for purposes of the refinery standard, and that the EPA intended to permit averaging among all emission points within the source category except for equipment leaks.

Comments on both the gasoline distribution rule and the refinery proposal indicated that the Agency needed to clarify which rule applied to which emissions points and whether averaging would apply to collocated emission points. Both proposed rules addressed similar emission points; for example, both proposed rules addressed storage tanks and equipment leaks where refineries were collocated with gasoline distribution operations. In the preamble accompanying the final gasoline distribution rule, the EPA indicated the intent to rely on SIC codes to distinguish between emission points at refineries covered by the gasoline distribution standard and those covered by the refinery standard. The Agency noted that the SIC code for particular equipment would indicate the department with managerial oversight responsibility for each emission point. However, the EPA specifically provided that this rule, if appropriate, would

modify the gasoline distribution standard to incorporate SIC code limits.

Today's rule identifies petroleum refinery process units and the gasoline loading rack emission points by SIC code for purposes of identifying the appropriate control requirements. A broad source category and affected source definition increases the opportunity to use flexible compliance options such as emissions averaging. Because the control technology under today's rule for gasoline loading racks is the same as the requirements under the gasoline distribution NESHAP, the required emissions reductions from gasoline loading racks would be at least as great as would have been required had gasoline loading racks been excluded from the petroleum refinery source category and affected source; due to the credit discount factors, overall emissions may be less than otherwise would be required if gasoline loading racks are included in an emissions averaging plan.

G. Emissions Averaging

The preamble to the proposed petroleum refinery rule requested comments on whether marine loading operations at refineries should be included in emissions averaging. The EPA also reopened the comment period for the proposed NESHAP for marine tank vessel loading operations (59 FR 44955) to request comment on whether marine terminals collocated at refineries should be moved to the petroleum refinery source category. In addition, as noted above, issues related to including gasoline distribution emissions in averaging at refineries were also raised in the proposed rule preamble.

During the comment period for the gasoline distribution NESHAP, commenters requested that gasoline bulk terminals contiguous to a refinery be regulated by the petroleum refinery NESHAP. Several commenters on the proposed petroleum refinery NESHAP and proposed marine tank vessel loading operations NESHAP supported averaging of refinery process unit emissions with emissions from marine terminals and gasoline distribution operations that are located at refineries. The commenters cited more cost-effective emission reduction as the advantage of including these emission points in emissions averaging, and specifically commented that the costs per megagram emission reduction of the marine loading controls are high. These commenters also claimed that emission calculation procedures for loading are well established and that adding marine loading to the averaging provisions will not appreciably increase the complexity

of enforcement. Other commenters opposed including marine loading and gasoline distribution emission points in emissions averaging. Some commenters claimed that these are separate source categories and that the Act does not permit averaging across source categories. Other commenters were of the opinion that the EPA has the flexibility to allow trading within a facility that includes units in different source categories. These commenters argued that it is unnecessary to redefine the source category to include marine loading operations and gasoline distribution operations collocated at refineries.

In the final rule, the definitions of the petroleum refinery source category and affected source have been changed to include gasoline loading racks classified under SIC code 2911 (Petroleum Refineries) and marine tank vessel loading operations that are located at refinery plant sites. Because marine loading operations and bulk gasoline transfer operations located at refineries are supplying raw materials to, or transferring products from, petroleum refinery process units, they are logically considered to be part of the same source as the petroleum refinery process units. The EPA considers this definition to be the most appropriate definition and, as noted by several commenters, to present fewer implementation problems.

A gasoline loading rack classified under SIC code 2911 or a marine tank vessel loading operation that is located at a petroleum refinery may be included in an emissions average with other refinery process unit emission points. Because these operations are included as part of a single source within one source category intersource averaging is not an issue.

In keeping with the EPA's stated goal of increasing flexibility in rulemakings, this decision has been made to provide more opportunities to average. This increases the opportunities for refiners to find cost-effective emission reductions from overall facility operations onsite. Costs and cost effectiveness of controlling a particular kind of emission point, such as marine loading, will vary depending on many site-specific factors. Emissions averaging allows the owner and operator to find the optimal control strategy for their particular situation.

The EPA is presently reviewing the emission averaging policy and considering whether any more flexibility can be provided while maintaining environmental protection. The issue of intersource averaging will be considered along with other aspects of the emissions averaging policy such

as limitations on the number of points allowed in an average. The EPA believes that any decision to provide additional flexibility must be based on careful consideration of enforcement issues as well as equity in environmental protection. Given the complexity of these issues, the EPA does not believe that the Refinery MACT standard is the appropriate place to address these issues. The EPA plans to examine the issue independently of any specific rulemaking. In this, the EPA plans to work closely with both the refining and chemical industries and other interested parties to determine if there are opportunities for increasing flexibility and reducing the burden associated with demonstrating compliance with the MACT rules while remaining within the law.

The EPA would like to clarify that the emissions averaging program was designed to result in equal or greater environmental protection while providing sources flexibility to reduce emissions in the most cost-effective manner. Specifically, allowing marine loading operations, and gasoline loading racks classified under SIC code 2911, located at a refinery to be included in emissions averages will result in equivalent or greater overall HAP emission reduction at each refinery. The averaging provisions are structured such that "debits" generated by not controlling an emission point that otherwise would require control must be balanced by achieving extra control at other refinery emission points covered by the NESHAP. The averaging provisions also require that a source demonstrate that compliance through averaging will not result in greater risk or hazard than compliance without averaging.

Some commenters were concerned that including marine loading in averages could result in uncontrolled peak emissions. With regard to the commenters' concerns about peak emissions, the quarterly cap on the ratio of debits to credits is intended to limit the possibility of exposure peaks. Furthermore, because loading occurs fairly frequently, and emissions from an individual vessel filling or loading event are relatively small, such emissions are not expected to cause significant exposure peaks. Moreover, no evidence has been presented that emissions averaging would permit a very different mix of emissions to occur than would point-by-point compliance. That is, peaks of exposures from batch streams, storage, and loading operations should be equally likely under point-by-point compliance as under emissions averaging, so emissions averaging does

not represent a less effective control strategy. Furthermore, in order to receive approval for an emissions average, the owner or operator is required to demonstrate that the emissions average does not increase the risk or hazard relative to compliance without averaging.

H. Monitoring, Recordkeeping, and Reporting

Several commenters alleged that the recordkeeping and reporting requirements of the proposed rule were extremely burdensome. The commenters requested that the EPA reduce the monitoring, recordkeeping, and reporting burden associated with the proposed rule. Commenters also requested that provisions be added to the final rule to avoid duplicative reporting for equipment subject to multiple NESHAP and NSPS. Other commenters requested that flexibility to allow alternative monitoring, recordkeeping, and reporting be incorporated into the final rule.

The EPA recognizes that unnecessary monitoring, recordkeeping, and reporting requirements would burden both the source and enforcement agencies. Prior to proposal, the EPA attempted to reduce the amount of monitoring, recordkeeping, and reporting to only that which is necessary to demonstrate compliance. For example, at proposal almost all reports were consolidated into the Notification of Compliance Status and the Periodic Reports. This was done to simplify and reduce the frequency of reporting. Sources also have the option of retaining records either in paper copy or in computer-readable formats, whichever is less burdensome. If multiple performance tests are conducted for the same kind of emission point using the same test method, only one complete test report is submitted along with summaries of the results of other tests. This reduces the number of lengthy test reports to be copied, reviewed, and submitted.

Site-specific test plans describing quality assurance in § 63.7(c) of 40 CFR part 63, subpart A are not required because the test methods cited in subpart CC already contain applicable quality assurance protocols. The quality assurance provisions in the individual test methods remain applicable and are not superseded by the nonapplicability of § 63.7(c) of subpart A. For continuously monitored parameters, periodic reporting is limited to excursions outside the established ranges and the in-range values are not required to be reported.

In response to the commenters, the EPA reevaluated whether monitoring, recordkeeping, and reporting requirements could be further reduced while maintaining the enforceability of the rule. The EPA has made the following changes in the promulgated rule to further reduce the monitoring, recordkeeping, and reporting burden:

(1) The requirement to submit an Initial Notification has been eliminated;

(2) Periodic reports are required to be submitted semiannually for all facilities that do not use emissions averaging (the proposal required quarterly reports if monitored parameters were out of range more than a specified percentage of the time);

(3) A reduction in the frequency for parameter monitoring and recording. The proposal required values of monitored parameters to be recorded every 15 minutes and all 15-minute records had to be retained for those days when excess emissions occurred. The final rule allows hourly monitoring and recording;

(4) Recordkeeping and reporting provisions that eliminate duplicate reporting for equipment subject to multiple NESHAP and NSPS were added to the applicability section (§ 63.640) of the final rule. The additions specify which rule applies and overrides the less stringent NSPS or NESHAP. For State and local regulation applicability determination, the final rule has been amended to state that the local regulatory authority (e.g., State or permitting authority) can decide how monitoring, recordkeeping, and reporting requirements can be consolidated, and can approve alternative monitoring, recordkeeping, and reporting requirements.

These reductions reduce the proposal monitoring, recordkeeping, and reporting burden by 25 percent. The EPA plans to continue to work with the industry as well as with other interested parties to identify further opportunities for reduction of the monitoring, recordkeeping, and reporting burden of the rule. The EPA will consider ways to eliminate overlapping requirements and to address any inconsistencies among the rules. The EPA will investigate the possibility of consolidating and simplifying the various rules while maintaining the same level of environmental protection. Assuming that the pilot project with the chemical industry is successful, the EPA expects to be able to complete the review of the Refinery rule monitoring, recordkeeping, and reporting requirements before the compliance date.

I. Subcategorization

Several commenters to the proposed petroleum refinery NESHAP requested that the EPA subcategorize refineries by size and/or location in an ozone attainment area. Other commenters stated that subcategorizing small refineries because of an arbitrary size exemption can result in an unfair competitive advantage. These commenters further elaborated that large refineries should not be penalized for an economy of scale achieved through its own effective competitiveness.

In response to these comments, the refinery data bases were subcategorized based on crude charge capacity. The refineries were also subcategorized by ozone attainment status and by refineries containing processes that are used to produce gasoline (such as catalytic cracking, coking, and catalytic reforming). Within each subcategory, the process vents, storage vessels, and equipment leaks data bases were sorted from most stringent control to least stringent. The MACT floor (average of the top 12 percent of sources) for each subcategory was identified.

The MACT floors for small refineries are not significantly different from the industry as a whole. The floor for process vents is the same for small refiners as for the entire industry. The floor for storage tanks would increase the materials vapor pressure cutoff from 10 kPa (1.5 psia) to 11 kPa (1.7 psia), which would result in a minimal cost savings since there are few petroleum liquids in this volatility range. The floor for equipment leaks would reduce the monitoring frequency; however, small refiners would still incur the cost of setting up and implementing an LDAR program.

Based on the EPA's analysis and the comments received during the public comment period, a separate subcategory for small refineries has not been included in the final rule. This decision was based on there being no clear relationship between refinery size or design and emission potential.

J. Economic Analysis

Comments were received on both the methodology of the economic analysis and the potential impacts of the analysis results. The EPA's economic model focused on estimating changes in product price and quantity of production for several petroleum products. Once the effects on price and quantity were evaluated, other impacts were estimated. The model the EPA used is predicated on neoclassical microeconomic theory.

The model assumed that those refineries with the highest per-unit

control are marginal (i.e., near the margin between shutdown and continuing operation) in the post-control markets, and that they also have the highest underlying per-unit cost of production. This assumption may result in an overstatement of the adverse impacts, such as closure, since the assumed relationship between per-unit control cost and per-unit production cost may not hold for all refineries. For more information, consult the "Economic Impact Analysis for the Petroleum Refinery NESHAP" in the docket.

Most of the comments about the economic analyses methodology were focused on possible impacts on other parts of the petroleum industry other than refineries. The economic analysis for this rule, like most of the EPA's economic analyses, focuses on the impacts on the industry being regulated and does not calculate impacts to other industries indirectly affected unless those impacts are significant. In this case, the impacts to indirectly affected industries were not calculated since the impacts estimated for the petroleum refinery industry were not significant, impacts to indirectly affected industries would likely be insignificant also.

K. Benefits Analysis

Comments noted that naphthalene is classified as a possible carcinogen, not a known carcinogen, and therefore should not be included in the risk analysis. Commenters also argued that the estimates for monetized VOC benefits were too high, since the VOC reductions claimed in the regulation would occur as a result of State Implementation Plans (SIP's) required by the Act. Other commenters wrote that the level of benefits from HAP emissions reduction was not of sufficient justification for pursuing the regulation.

When the rule was proposed, naphthalene was classified as a possible human carcinogen. Naphthalene is no longer classified as a possible human carcinogen and is not included in the risk analysis for the final rule.

To estimate the benefits of reducing VOC, the EPA used a 1989 study conducted by the Office of Technology Assessment (OTA). The study examined a variety of acute health impacts related to ozone exposure as well as the benefits of reduced ozone concentrations for selected agricultural crops. A number of factors were not considered in the analysis, including chronic health effects and health impacts for attainment areas.

As to the comment about some of the benefits being attributable to VOC

emission reductions brought about by implementing SIP's, the EPA attempted to include in the baseline all possible impacts from SIP implementation. Control of VOC in this rule will be incorporated into future SIP's by affecting their baselines, thus making the emission reductions needed to meet them less, and leading to lower costs for petroleum refineries to meet those SIP's. Therefore, control of VOC emissions in this rule will lead to lower costs to future SIP implementation. Also, the emission streams from petroleum refineries are primarily VOC, with a small fraction of VOC being HAP. Control of any petroleum refinery emission stream involves control of VOC as well as HAP. Thus, any benefits estimated to occur from a rule that controls VOC, though their control is of secondary importance, should be included as benefits of the rule.

L. Emissions Data

Commenters raised concerns about the amount and quality of the data on HAP emissions, and the uncertainties in the emission estimates. Throughout the rulemaking, the EPA has been aware of these concerns. During the course of this rulemaking, the EPA requested information from the petroleum refining industry on emissions and emission control technologies. The industry provided sufficient information on the emission control technologies to determine the best controlled facilities, as required by section 112 of the Act. However, the information received on existing emission control levels was limited because it was not available. Thus, there is uncertainty in the refinery baseline emission estimates, and emission reductions and other benefits achieved from the emission controls required to comply with the rule. The EPA and the petroleum refinery industry are unable to reduce this uncertainty at this time. The Agency has characterized the costs and emission reductions of the requirements of this rule as accurately as possible. While there is a great deal of qualitative information on the benefits of this rule, the uncertainty in the emission estimates and the monetary value that can be placed on the emission reductions limits the Agency's ability to directly quantify all the benefits of the refinery MACT rule. The EPA does know, however, that the controls required in this rulemaking are in widespread use in the refining industry and that they provide substantial emission reductions.

Under section 112(f) of the Act, the EPA must determine whether further control of refinery emissions is

necessary to protect the health of the general public. This determination will require more accurate emission estimates than currently exist. The EPA has made a commitment to work cooperatively with industry to identify the data needed to improve the emission estimates and any other information that is required to determine the health risks that may remain after implementation of the refinery MACT rule.

VI. Changes to NSPS

The changes to 40 CFR part 60, subparts VV and QQQ are promulgated with minor edits for clarity and consistency.

VII. Administrative Requirements

A. Docket

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

B. Paperwork Reduction Act

The information collection requirements in this rule have been approved by the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* and have been assigned control number 2060-0340. This collection of information has an estimated annual reporting burden averaging 320 hours per respondent and an estimated annual recordkeeping burden averaging 2,880 hours per respondent. These estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

This reflects a reduction of the proposal monitoring, recordkeeping, and reporting burden of 25 percent. The EPA plans to continue to work with the industry as well as with other interested parties to identify further opportunities for reduction of the monitoring, recordkeeping, and reporting burden of the rule. The EPA will consider ways to eliminate overlapping requirements and

to address any inconsistencies among the rules. The EPA will investigate the possibility of consolidating and simplifying the various rules while maintaining the same level of environmental protection. Assuming that the pilot project with the chemical industry is successful, the EPA expects to be able to complete the review of the Refinery rule monitoring, recordkeeping, and reporting requirements before the compliance date.

Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to Chief, Information Policy Branch; EPA; 401 M St. SW., (Mail Code 2136); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked "Attention: Desk Officer for EPA."

C. Executive Order 12866

Under Executive Order 12866 (58 FR 5173 (October 4, 1993)), the Agency must determine whether the regulatory action is "significant" and therefore subject to OMB review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

- (1) Have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

This action is a "significant regulatory action" within the meaning of Executive Order 12866. The EPA has submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

D. Regulatory Flexibility Act

Pursuant to the Regulatory Flexibility Act of 1980, 5 U.S.C. 601 *et seq.*, when an agency publishes a notice of rulemaking, for a rule that will have a significant effect on a substantial number of small entities, the agency

must prepare and make available for public comment a regulatory flexibility analysis (RFA) that considers the effect of the rule on small entities (i.e., small businesses, small organizations, and small governmental jurisdictions). In assessing the regulatory approach for dealing with small entities in today's final rule, the EPA guidelines indicate that an economic impact should be considered significant if it meets one of the following criteria:

(1) Compliance increases annual production costs by more than 5 percent, assuming costs are passed on to consumers;

(2) Compliance costs as a percentage of sales for small entities are at least 10 percent more than compliance costs as a percentage of sales for large entities;

(3) Capital costs of compliance represent a "significant" portion of capital available to small entities, considering internal cash flow plus external financial capabilities, or

(4) Regulatory requirements are likely to result in closure of small entities.

Data were not readily available to determine if criteria (1) and (3) were met or not, so the analysis focused on the other two. Results from the economic impact analysis indicate that between zero and seven refiners, all of which are classified as small, are at risk of closure (refer to the "Economic Impact Analysis of the Regulatory Alternatives for the Petroleum Refineries NESHAP" in the *Background Information Documents* section). While this percentage of net closures is less than 20 percent of the total number of small refineries (88), it was deemed high enough for carrying out an RFA on that basis alone. Criterion (2), however, was satisfied. The compliance costs-to-sales ratio for the small refiners was more than 10 percent greater than the same ratio calculated for all other refiners.

There are four reasons why small entities are disproportionately affected by the regulation. The first is the fact that they tend to own smaller facilities, and therefore have smaller economies of scale. Because of the smaller economies of scale, per-unit costs of production and compliance are higher for the small refiners compared to others. Related to this is the fact that small refiners have less ability to produce differentiated products. This ability, called complexity, increases with increasing refinery capacity. A large refinery can respond to a relative increase in production costs for one product by increasing production of a product now relatively cheaper to produce, an ability most small refiners rarely enjoy.

A second reason is they have fewer capital resources. Small refineries have

less ability to finance the capital expenditures needed to purchase the equipment required to comply with the regulation. A third reason is the difference in internal structure. None of the small refiners are vertically or horizontally integrated, and in all but a few cases are not the subsidiary of a large parent company. The small refiners are typically independent owners and operators of their facilities, and most are owners of a single refinery. They do not possess the ability to shift production between different refineries and have less market power than their large competitors.

A fourth reason why smaller refiners experience greater economic impacts than other refiners is due to the small industry-level price increases (less than 1 percent in all cases). It is unlikely that small refiners will be able to recover annualized control costs by increasing product prices, since the large refiners will not be significantly impacted. As seen in the examination of criterion (2), the large refiners will not be significantly affected from compliance with the regulation.

In calculating the number of closures, the assumption was made that those refineries with the highest per-unit control costs were marginal after compliance with the regulation. While this assumption is often useful in closure analysis, it is not always true. The assumption is consistent with perfect competition theory that presumes all firms are price-takers. If a refiner does have some monopoly power in a particular market, then it is possible a refiner experiencing some economic distress could continue to operate for some period while complying with the regulation. It is a conservative assumption that likely biases the results to overstate the number of refinery closures and other impacts of the proposed regulation.

To mitigate the economic impacts on small refiners, the Agency has considered whether to subcategorize the MACT floors for the various emission sources or to allow refiners more time to comply with the regulation. The Agency has decided not to include a separate subcategory for small refiners, but has decided to allow refiners more time to comply with various requirements for control of equipment leak and storage vessel emissions (refer to section V, "Significant Comments and Changes to the Proposed Standards").

The definition of small refinery used in the analysis is 50,000 bbl per stream day production capacity. This differs from the definition of 75,000 barrels per stream current as of May 1, 1992, a

definition announced by the Small Business Administration that day in the *Federal Register* (57 FR 18808).

E. Unfunded Mandates

Under section 202 of the Unfunded Mandates Reform Act of 1995 ("Unfunded Mandates Act"), signed into law on March 22, 1995, the EPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated costs to State, local, or tribal governments in the aggregate, or to the private sector, of \$100 million or more. Under section 205, the EPA must select the most cost effective and least burdensome alternative that achieves the objectives of the rule and is consistent with statutory requirements. Section 203 requires the EPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule.

The EPA has determined that the action promulgated today does not include a Federal mandate that may result in estimated costs of \$100 million or more to either State, local, or tribal governments in the aggregate, or to the private sector. Therefore, the requirements of the Unfunded Mandates Act do not apply to this action.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Gasoline, Intergovernmental relations, Natural gas, Volatile organic compounds.

40 CFR Part 63

Air pollution control, Hazardous air pollutants, Petroleum refineries, Reporting and recordkeeping requirements.

Dated: July 28, 1995.

Carol M. Browner,
Administrator.

For the reasons set out in the preamble, parts 9, 60, and 63 of title 40, chapter I, of the Code of Federal Regulations are amended as follows:

PART 9—OMB APPROVALS UNDER THE PAPERWORK REDUCTION ACT

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

Authority: 7 U.S.C. 135 et seq., 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251 et seq., 1311, 1313d, 1314, 1321, 1326, 1330, 1344, 1345(d), and (e), 1381; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975

as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486(c).

(4) For each inspection conducted in accordance with § 60.485(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

* * * * *

Subpart QQQ—[Amended]

* * * * *

5. Section 60.691 is amended by revising the definition of "closed vent system" to read as follows:

§ 60.691 Definitions.

* * * * *

Closed vent system means a system that is not open to the atmosphere and that is composed of piping, connections, and, if necessary, flow-inducing devices that transport gas or vapor from an emission source to a control device. If gas or vapor from regulated equipment are routed to a process (e.g., to a petroleum refinery fuel gas system), the process shall not be considered a closed vent system and is not subject to the closed vent system standards.

* * * * *

6. Section 60.692-3 is amended by revising paragraph (d) to read as follows:

§ 60.692-3 Standards: Oil-water separators.

* * * * *

(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in §§ 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

* * * * *

7. Section 60.693-2 is amended by revising paragraphs (a)(1)(i) introductory text and (a)(1)(i)(A) to read as follows:

§ 60.693-2 Alternative standards for oil-water separators.

* * * * *

(a) * * *

(1) * * *

(i) The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.

(A) A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

* * * * *

8. Section 60.695 is amended by adding paragraphs (a)(3)(i) and (a)(3)(ii) to read as follows:

§ 60.695 Monitoring of operations.

* * * * *

(a) * * *

(3) * * *

(i) For a carbon adsorption system that regenerates the carbon bed directly onsite, a monitoring device that continuously indicates and records the volatile organic compound concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

* * * * *

9. Section 60.697 is amended by revising paragraphs (f)(3)(i), (f)(3)(ii); and by adding paragraphs (f)(3)(x) (A) and (B) to read as follows:

§ 60.697 Recordkeeping requirements.

* * * * *

(f) * * *

(3) * * *

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

* * * * *

(x) * * *

(A) Each owner or operator of an affected facility that uses a carbon adsorber which is regenerated directly onsite shall maintain continuous records of the volatile organic compound concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(B) If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and

time that the existing carbon in the control device is replaced with fresh carbon.

* * * * *

10. Section 60.698 is amended by adding paragraphs (d)(3)(i) and (d)(3)(ii) to read as follows:

§ 60.698 Reporting requirements.

* * * * *

(d) * * *

(3) * * *

(i) Each 3-hour period of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases from a carbon adsorber which is regenerated directly onsite is more than 20 percent greater than the design exhaust gas concentration level or reading.

(ii) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in § 60.695(a)(3)(ii).

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

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

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

Subpart R—[Amended]

2. Section 63.420 is amended by adding paragraph (i) to read as follows:

§ 63.420 Applicability.

* * * * *

(i) A bulk gasoline terminal or pipeline breakout station with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with subpart CC, §§ 63.646, 63.648, 63.649, and 63.650 is not subject to subpart R standards, except as specified in subpart CC, § 63.650.

* * * * *

3. Part 63 is amended by adding subpart CC consisting of §§ 63.640 through 63.679 to read as follows:

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

Sec.

63.640 Applicability and designation of affected source.

63.641 Definitions.

63.642 General standards.

63.643 Miscellaneous process vents provisions.

63.644 Monitoring provisions for miscellaneous process vents.

63.645 Test methods and procedures for miscellaneous process vents.

63.646 Storage vessel provisions.

63.647 Wastewater provisions.

63.648 Equipment leak standards.

63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

63.650 Gasoline loading rack provisions.

63.651 Marine vessel tank loading operations provisions.

63.652 Emissions averaging provisions.

63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.

63.654 Reporting and recordkeeping requirements.

63.655 through 63.679 [Reserved]

Appendix to Subpart CC—Tables

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

§ 63.640 Applicability and designation of affected source.

(a) This subpart applies to petroleum refining process units and to related emission points that are specified in paragraphs (c)(5) through (c)(7) of this section that are located at a plant site that meet the criteria in paragraphs (a)(1) and (a)(2) of this section:

(1) Are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act; and

(2) Emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart.

(b) For process units that are designed and operated as flexible operation units, the applicability of this subpart shall be determined for existing sources based on the expected utilization for the first 5 years after startup.

(i) If the predominant use of the flexible operation unit, as described in paragraphs (b)(1)(i) and (b)(1)(ii) of this section, is as a petroleum refining process unit, as defined in § 63.641, then the flexible operation unit shall be subject to the provisions of this subpart.

(i) Except as provided in paragraph (b)(1)(ii) of this section, the predominant use of the flexible operation unit shall be the use representing the greatest annual operating time.

(ii) If the flexible operation unit is used as a petroleum refining process unit and for another purpose equally based on operating time, then the predominant use of the flexible operation unit shall be the use that produces the greatest annual production on a mass basis.

(2) The determination of applicability of this subpart to petroleum refining

process units that are designed and operated as flexible operation units shall be reported as specified in § 63.654(h)(6)(i).

(c) For the purpose of this subpart, the affected source shall comprise all emission points, in combination, listed in paragraphs (c)(1) through (c)(7) of this section that are located at a single refinery plant site.

(1) All miscellaneous process vents from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(2) All storage vessels associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(3) All wastewater streams and treatment operations associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(4) All equipment leaks from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(5) All gasoline loading racks classified under Standard Industrial Classification code 2911 meeting the criteria in paragraph (a) of this section;

(6) All marine vessel loading operations located at a petroleum refinery meeting the criteria in paragraph (a) of this section and the applicability criteria of subpart Y, § 63.560; and

(7) All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery meeting the criteria in paragraph (a) of this section.

(d) The affected source subject to this subpart does not include the emission points listed in paragraphs (d)(1) through (d)(4) of this section.

(1) Stormwater from segregated stormwater sewers;

(2) Spills; and

(3) Equipment that is intended to operate in organic hazardous air pollutant service, as defined in § 63.641 of this subpart, for less than 300 hours during the calendar year.

(4) Catalytic cracking unit and catalytic reformer catalyst regeneration vents, and sulfur plant vents.

(e) The owner or operator shall follow the procedures specified in paragraphs (e)(1) and (e)(2) of this section to determine whether a storage vessel is part of a source to which this subpart applies.

(1) Where a storage vessel is used exclusively by a process unit, the

storage vessel shall be considered part of that process unit.

(i) If the process unit is a petroleum refining process unit subject to this subpart, then the storage vessel is part of the affected source to which this subpart applies.

(ii) If the process unit is not subject to this subpart, then the storage vessel is not part of the affected source to which this subpart applies.

(2) If a storage vessel is not dedicated to a single process unit, then the applicability of this subpart shall be determined according to the provisions in paragraphs (e)(2)(i) through (e)(2)(iii) of this section.

(i) If a storage vessel is shared among process units and one of the process units has the predominant use, as determined by paragraphs (e)(2)(i)(A) and (e)(2)(i)(B) of this section, then the storage vessel is part of that process unit.

(A) If the greatest input on a volume basis into the storage vessel is from a process unit that is located on the same plant site, then that process unit has the predominant use.

(B) If the greatest input on a volume basis into the storage vessel is provided from a process unit that is not located on the same plant site, then the predominant use shall be the process unit that receives the greatest amount of material on a volume basis from the storage vessel at the same plant site.

(ii) If a storage vessel is shared among process units so that there is no single predominant use, and at least one of those process units is a petroleum refining process unit subject to this subpart, the storage vessel shall be considered to be part of the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the storage vessel to any of the petroleum refining process units subject to this subpart.

(iii) If the predominant use of a storage vessel varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that storage vessel during the year preceding promulgation of this subpart. This determination shall be reported as specified in § 63.654(h)(6)(ii) of this subpart.

(f) The owner or operator shall follow the procedures specified in paragraphs (f)(1) through (f)(5) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies.

(1) If the greatest input to the distillation unit is from a process unit

located on the same plant site, then the distillation unit shall be assigned to that process unit.

(2) If the greatest input to the distillation unit is provided from a process unit that is not located on the same plant site, then the distillation unit shall be assigned to the process unit located at the same plant site that receives the greatest amount of material from the distillation unit.

(3) If a distillation unit is shared among process units so that there is no single predominant use, as described in paragraphs (f)(1) and (f)(2) of this section, and at least one of those process units is a petroleum refining process unit subject to this subpart, the distillation unit shall be assigned to the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the distillation unit to any of the petroleum refining process units subject to this rule.

(4) If the process unit to which the distillation unit is assigned is a petroleum refining process unit subject to this subpart and the vent stream contains greater than 20 parts per million by volume total organic hazardous air pollutants, then the vent from the distillation unit is considered a miscellaneous process vent (as defined in § 63.641 of this subpart) and is part of the source to which this subpart applies.

(5) If the predominant use of a distillation unit varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that distillation unit during the year preceding promulgation of this subpart. This determination shall be reported as specified in § 63.654(f)(1)(ii).

(g) The provisions of this subpart do not apply to the processes specified in paragraphs (g)(1) through (g)(7) of this section.

(1) Research and development facilities, regardless of whether the facilities are located at the same plant site as a petroleum refining process unit that is subject to the provisions of this subpart;

(2) Equipment that does not contain any of the hazardous air pollutants listed in table 1 of this subpart that is located within a petroleum refining process unit that is subject to this subpart;

(3) Units processing natural gas liquids;

(4) Units that are used specifically for recycling discarded oil;

(5) Shale oil extraction units;

(6) Ethylene processes; and

(7) Process units and emission points subject to subparts F, G, H, and I of this part.

(h) Except as provided in paragraphs (k), (l), or (m) of this section, sources subject to this subpart are required to achieve compliance on or before the dates specified in paragraphs (h)(1) through (h)(4) of this section.

(1) New sources that commence construction or reconstruction after July 14, 1994 shall be in compliance with this subpart upon initial startup or the date of promulgation of this subpart, whichever is later, as provided in § 63.6(b) of subpart A of this part.

(2) Except as provided in paragraphs (h)(3) through (h)(5) of this section, existing sources shall be in compliance with this subpart no later than August 18, 1998, except as provided in § 63.6(c) of subpart A of this part, or unless an extension has been granted by the Administrator as provided in § 63.6(i) of subpart A of this part.

(3) [Reserved].

(4) Existing Group 1 floating roof storage vessels shall be in compliance with § 63.646 at the next degassing and cleaning activity or within 10 years after promulgation of the rule, whichever is first.

(5) An owner or operator may elect to comply with the provisions of § 63.648 (c) through (f) as an alternative to the provisions of § 63.648 (a) and (b). In such cases, the owner or operator shall comply no later than the dates specified in paragraphs (h)(5)(i) through (h)(5)(iii) of this section.

(i) Phase I (see table 2 of this subpart), beginning on August 18, 1998;

(ii) Phase II (see table 2 of this subpart), beginning no later than August 18, 1999; and

(iii) Phase III (see table 2 of this subpart), beginning no later than June 18, 2001.

(i) If an additional petroleum refining process unit is added to a plant site that is a major source as defined in section 112(a) of the Clean Air Act, the addition shall be subject to the requirements for a new source if it meets the criteria specified in paragraphs (i)(1) through (i)(3) of this section:

(1) It is an addition that meets the definition of construction in § 63.2 of subpart A of this part;

(2) Such construction commenced after July 14, 1994; and

(3) The addition has the potential to emit 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

(j) If any change is made to a petroleum refining process unit subject to this subpart, the change shall be

subject to the requirements for a new source if it meets the criteria specified in paragraphs (j)(1) and (j)(2) of this section:

(1) It is a change that meets the definition of reconstruction in § 63.2 of subpart A of this part; and

(2) Such reconstruction commenced after July 14, 1994.

(k) If an additional petroleum refining process unit is added to a plant site or a change is made to a petroleum refining process unit and the addition or change is determined to be subject to the new source requirements according to paragraphs (i) or (j) of this section it must comply with the requirements specified in paragraphs (k)(1) and (k)(2) of this section:

(1) The reconstructed source, addition, or change shall be in compliance with the new source requirements upon initial startup of the reconstructed source or by the date of promulgation of this subpart, whichever is later; and

(2) The owner or operator of the reconstructed source, addition, or change shall comply with the reporting and recordkeeping requirements that are applicable to new sources. The applicable reports include, but are not limited to:

(i) The application for approval of construction or reconstruction shall be submitted as soon as practical before the construction or reconstruction is planned to commence (but it need not be sooner than 90 days after the date of promulgation of this subpart);

(ii) The Notification of Compliance Status report as required by § 63.654(f) for a new source, addition, or change;

(iii) Periodic Reports and Other Reports as required by § 63.654 (g) and (h);

(iv) Reports and notifications required by § 60.487 of subpart VV of part 60 or § 63.182 of subpart H of this part. The requirements for subpart H are summarized in table 3 of this subpart;

(v) Reports required by 40 CFR 61.357 of subpart FF;

(vi) Reports and notifications required by § 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3) of subpart R. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §§ 63.566 and 63.567 of subpart Y of this part. These requirements are summarized in table 5 of this subpart.

(l) If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, gasoline loading rack, or marine tank vessel loading operation that meets the criteria in paragraphs (c)(1) through

(c)(7) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emission point(s) (as defined in § 63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to paragraphs (i) or (j) of this section, the requirements in paragraphs (l)(1) through (l)(3) of this section shall apply. Examples of process changes include, but are not limited to, changes in production capacity, or feed or raw material where the change requires construction or physical alteration of the existing equipment or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph and paragraph (m) of this section, process changes do not include: Process upsets, unintentional temporary process changes, and changes that are within the equipment configuration and operating conditions documented in the Notification of Compliance Status report required by § 63.654(f).

(1) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit are subject to the requirements for an existing source.

(2) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit shall be in compliance with this subpart by the dates specified in paragraphs (l)(2)(i) or (l)(2)(ii) of this section, as applicable.

(i) If a petroleum refining process unit is added to a plant site or an emission point(s) is added to any existing petroleum refining process unit, the added emission point(s) shall be in compliance upon initial startup of any added petroleum refining process unit or emission point(s) or by 3 years after the date of promulgation of this subpart, whichever is later.

(ii) If a deliberate operational process change to an existing petroleum refining process unit causes a Group 2 emission point to become a Group 1 emission point (as defined in § 63.641), the owner or operator shall be in compliance upon initial startup or by 3 years after the date of promulgation of this subpart, whichever is later, unless the owner or operator demonstrates to the Administrator that achieving compliance will take longer than making the change. If this demonstration is made to the Administrator's satisfaction, the owner or operator shall follow the procedures in paragraphs (m)(1) through (m)(3) of

this section to establish a compliance date.

(3) The owner or operator of a petroleum refining process unit or of a storage vessel, miscellaneous process vent, wastewater stream, gasoline loading rack, or marine tank vessel loading operation meeting the criteria in paragraphs (c)(1) through (c)(7) of this section that is added to a plant site and is subject to the requirements for existing sources shall comply with the reporting and recordkeeping requirements that are applicable to existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (l)(3)(vii) of this section. A process change to an existing petroleum refining process unit shall be subject to the reporting requirements for existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (l)(3)(vii) of this section. The applicable reports include, but are not limited to:

(i) The Notification of Compliance Status report as required by § 63.654(f) for the emission points that were added or changed;

(ii) Periodic Reports and other reports as required by § 63.654 (g) and (h);

(iii) Reports and notifications required by sections of subpart A of this part that are applicable to this subpart, as identified in table 6 of this subpart.

(iv) Reports and notifications required by § 63.182 of subpart H of this part, or § 60.407 of subpart VV of part 60. The requirements of subpart H are summarized in table 3 of this subpart;

(v) Reports required by § 61.357 of subpart FF;

(vi) Reports and notifications required by § 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3) of subpart R of this part. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by § 63.567 of subpart Y of this part. These requirements are summarized in table 5 of this subpart.

(m) If a change that does not meet the criteria in paragraph (l) of this section is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in § 63.641), then the owner or operator shall comply with the requirements of this subpart for existing sources for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1.

(1) The owner or operator shall submit to the Administrator for approval a compliance schedule, along with a justification for the schedule.

(2) The compliance schedule shall be submitted within 180 days after the change is made or the information regarding the change is known to the source, unless the compliance schedule has been previously submitted to the permitting authority. The compliance schedule may be submitted in the next Periodic Report if the change is made after the date the Notification of Compliance Status report is due.

(3) The Administrator shall approve or deny the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification. Approval is automatic if not received from the Administrator within 120 calendar days of receipt.

(n) Overlap of subpart CC with other regulations for storage vessels.

(1) After the compliance dates specified in paragraph (h) of this section, a Group 1 or Group 2 storage vessel that is part of an existing source and is also subject to the provisions of 40 CFR part 60 subpart Kb is required to comply only with the requirements of 40 CFR part 60 subpart Kb.

(2) After the compliance dates specified in paragraph (h) of this section a Group 1 storage vessel that is part of a new source and is subject to 40 CFR part 60, subpart Kb is required to comply only with this subpart.

(3) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to the control requirements in § 60.112b of 40 CFR part 60, subpart Kb is required to comply only with 40 CFR part 60, subpart Kb.

(4) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to the § 60.110b subpart Kb, but is not required to apply controls by § 63.110b or 63.112b of subpart Kb is required to comply only with this subpart.

(5) After the compliance dates specified in paragraph (h) of this section a Group 1 storage vessel that is also subject to the provisions of 40 CFR part 60, subparts K or Ka is required to only comply with the provisions of this subpart.

(6) After compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the control requirements of 40 CFR part 60, subparts K or Ka is required to only comply with the provisions of 40 CFR part 60, subparts K or Ka.

(7) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to 40 CFR part 60, subparts K or

Ka, but not to the control requirements of 40 CFR part 60, subparts K or Ka, is required to comply only with this subpart.

(o) Overlap of this subpart CC with other regulations for wastewater.

(1) After the compliance dates specified in paragraph (h) of this section a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required to comply only with this subpart.

(2) After the compliance dates specified in paragraph (h) of this section a Group 1 or Group 2 wastewater stream that is conveyed, stored, or treated in a wastewater stream management unit that also receives streams subject to the provisions of §§ 63.133 through 63.147 of subpart G wastewater provisions of this part shall comply as specified in paragraphs (o)(2)(i) through (o)(2)(iii) of this section. Compliance with the provisions of paragraph (o)(2) of this section shall constitute compliance with the requirements of this subpart for that wastewater stream.

(i) The provisions in §§ 63.133 through 63.137 and § 63.140 of subpart G for all equipment used in the storage and conveyance of the Group 1 or Group 2 wastewater stream.

(ii) The provisions in both 40 CFR part 61, subpart FF and in §§ 63.138 and 63.139 of subpart G for the treatment and control of the Group 1 or Group 2 wastewater stream.

(iii) The provisions in §§ 63.143 through 63.148 of subpart G for monitoring and inspections of equipment and for recordkeeping and reporting requirements. The owner or operator is not required to comply with the monitoring, recordkeeping, and reporting requirements associated with the treatment and control requirements in 40 CFR part 61, subpart FF, §§ 61.355 through 61.357.

(p) Overlap of subpart CC with other regulations for equipment leaks. After the compliance dates specified in paragraph (h) of this section equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 are required to comply only with the provisions specified in this subpart.

(q) For overlap of subpart CC with local or State regulations, the permitting authority for the affected source may allow consolidation of the monitoring, recordkeeping, and reporting requirements under this subpart with the monitoring, recordkeeping, and reporting requirements under other applicable requirements in 40 CFR parts 60, 61, or 63, and in any 40 CFR part 52 approved State implementation plan provided the implementation plan

allows for approval of alternative monitoring, reporting, or recordkeeping requirements and provided that the permit contains an equivalent degree of compliance and control.

§ 63.641 Definitions.

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

Affected source means the collection of emission points to which this subpart applies as determined by the criteria in § 63.640. The term "affected source," as used in this subpart, has the same meaning as the term "affected source" in subpart A of this part.

Aliphatic means open-chained structure consisting of paraffin, olefin and acetylene hydrocarbons and derivatives.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

By compound means by individual stream components, not by carbon equivalents.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Closed vent system means a system that is not open to the atmosphere and is configured of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device or back into the process. If gas or vapor from regulated equipment is routed to a process (e.g., to a petroleum refinery fuel gas system), the process shall not be considered a closed vent system and is not subject to closed vent system standards.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of organic hazardous air pollutant vapors.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation. For the purpose of reporting and recordkeeping, connector means joined fittings that are accessible.

Continuous record means documentation, either in hard copy or

computer readable form, of data values measured at least once every hour and recorded at the frequency specified in § 63.654(i).

Continuous recorder means a data recording device recording an instantaneous data value or an average data value at least once every hour.

Control device means any equipment used for recovering, removing, or oxidizing organic hazardous air pollutants. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For miscellaneous process vents (as defined in this section), recovery devices (as defined in this section) are not considered control devices.

Delayed coker vent means a vent that is typically intermittent in nature, and usually occurs only during the initiation of the depressuring cycle of the decoking operation when vapor from the coke drums cannot be sent to the fractionator column for product recovery, but instead is routed to the atmosphere through a closed blowdown system or directly to the atmosphere in an open blowdown system. The emissions from the decoking phases of delayed coker operations, which include coke drum deheading, draining, or decoking (coke cutting), are not considered to be delayed coker vents.

Distillate receiver means overhead receivers, overhead accumulators, reflux drums, and condenser(s) including ejector-condenser(s) associated with a distillation unit.

Distillation unit means a device or vessel in which one or more feed streams are separated into two or more exit streams, each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and the vapor phases by vaporization and condensation as they approach equilibrium within the distillation unit. Distillation unit includes the distillate receiver, reboiler, and any associated vacuum pump or steam jet.

Emission point means an individual miscellaneous process vent, storage vessel, wastewater stream, or equipment leak associated with a petroleum refinery process unit; an individual storage vessel or equipment leak associated with a bulk gas terminal or pipeline breakout station classified under Standard Industrial Classification code 2911; a gasoline loading rack classified under Standard Industrial Classification code 2911; or a marine tank vessel loading operation located at a petroleum refinery.

Equipment leak means emissions of organic hazardous air pollutants from a pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system "in organic hazardous air pollutant service" as defined in this section. Vents from wastewater system drains, tank mixers, and sample valves on storage tanks are not equipment leaks.

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

Flexible operation unit means a process unit that manufactures different products periodically by alternating raw materials or operating conditions. These units are also referred to as campaign plants or blocked operations.

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

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen and other miscellaneous species.

Gasoline loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill gasoline cargo tanks.

Group 1 gasoline loading rack means any gasoline loading rack classified under Standard Industrial Classification code 2911 that emits from the vapor collection and processing system 10 milligrams of total organic compounds per liter of gasoline loaded.

Group 1 marine tank vessel means a vessel loaded at any land- or sea-based terminal or structure that loads liquid commodities with vapor pressures greater than or equal to 10.3 kilopascals in bulk onto marine tank vessels, that emits greater than 9.1 megagrams of any individual HAP or 13.6 megagrams of any combination of HAP annually after August 18, 1999.

Group 1 miscellaneous process vent means a miscellaneous process vent for which the volatile organic compound concentration, or the total organic

concentration (minus ethane and methane), is greater than or equal to 20 parts per million by volume, and the total volatile organic compound emissions are greater than or equal to 33 kilograms per day for existing and 7 kilograms per day for new sources at the outlet of the final recovery device (if any) and prior to any control device and prior to discharge to the atmosphere.

Group 1 storage vessel means a storage vessel at an existing source that has a design storage capacity greater than or equal to 177 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals and HAP liquid concentration greater than 4 percent by weight total organic HAP; a storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals and HAP liquid concentration greater than 2 percent by weight total organic HAP; or a storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters and less than 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 77 kilopascals and HAP liquid concentration greater than 2 percent by weight total organic HAP.

Group 1 wastewater stream means a wastewater stream at a petroleum refinery with a total annual benzene loading of 10 megagrams per year or greater as calculated according to the procedures in 40 CFR 61.342 of subpart FF of part 61 that has a flow rate of 0.02 liters per minute or greater, a benzene concentration of 10 parts per million by weight or greater, and is not exempt from control requirements under the provisions of 40 CFR part 61, subpart FF.

Group 2 gasoline loading rack means a gasoline loading rack classified under Standard Industrial Classification code 2911 that does not meet the definition of a Group 1 gasoline loading rack.

Group 2 marine tank vessel means a marine tank vessel that does not meet the definition of a Group 1 marine tank vessel.

Group 2 miscellaneous process vent means a miscellaneous process vent that does not meet the definition of a Group 1 miscellaneous process vent.

Group 2 storage vessel means a storage vessel that does not meet the definition of a Group 1 storage vessel.

Group 2 wastewater stream means a wastewater stream that does not meet the definition of Group 1 wastewater stream.

Hazardous air pollutant or HAP means one of the chemicals listed in section 112(b) of the Clean Air Act.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section present is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.593(d) of part 60, subpart GGG.

In organic hazardous air pollutant service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of § 63.180(d) of subpart H of this part and table 1 of this subpart. The provisions of § 63.180(d) of subpart H also specify how to determine that a piece of equipment is not in organic HAP service.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the stored liquid at the temperature equal to the highest calendar-month average of the liquid storage temperature for liquids stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored at the ambient temperature, as determined:

(1) In accordance with methods specified in § 63.111 of subpart G of this part;

(2) From standard reference texts; or

(3) By any other method approved by the Administrator.

Miscellaneous process vent means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit meeting the criteria specified in § 63.640(a). Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. Miscellaneous process vents include vent streams from: caustic wash

accumulators, distillation tower condensers/accumulators, flash/knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum (steam) ejectors, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. Miscellaneous process vents do not include:

(1) Gaseous streams routed to a fuel gas system;

(2) Relief valve discharges;

(3) Leaks from equipment regulated under § 63.648;

(4) Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations;

(5) In situ sampling systems (onstream analyzers);

(6) Catalytic cracking unit catalyst regeneration vents;

(7) Catalytic reformer regeneration vents;

(8) Sulfur plant vents;

(9) Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;

(10) Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, subpart G of this part, or 40 CFR part 61, subpart FF;

(11) Coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge, deheading, draining, or decoking (coke cutting) or pressure testing after decoking; and

(12) Vents from storage vessels.

Operating permit means a permit required by 40 CFR parts 70 or 71.

Organic hazardous air pollutant or organic HAP in this subpart, means any of the organic chemicals listed in table 1 of this subpart.

Petroleum-based solvents means mixtures of aliphatic hydrocarbons or mixtures of one and two ring aromatic hydrocarbons.

Periodically discharged means discharges that are intermittent and associated with routine operations. Discharges associated with maintenance activities or process upsets are not considered periodically discharged miscellaneous process vents and are therefore not regulated by the petroleum refinery miscellaneous process vent provisions.

Petroleum refining process unit means a process unit used in an establishment primarily engaged in petroleum refining as defined in the Standard Industrial

Classification code for petroleum refining (2911), and used primarily for the following:

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

(2) Separating petroleum; or

(3) Separating, cracking, reacting, or reforming intermediate petroleum streams.

(4) Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants.

Plant site means all contiguous or adjoining property that is under common control including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Primary fuel means the fuel that provides the principal heat input (i.e., more than 50 percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

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

Process unit means the equipment assembled and connected by pipes or ducts to process raw and/or intermediate materials and to manufacture an intended product. A process unit includes any associated storage vessels. For the purpose of this subpart, process unit includes, but is not limited to, chemical manufacturing process units and petroleum refining process units.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not considered a process unit shutdown. An unscheduled

work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, or would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown is not considered a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not considered process unit shutdowns.

Recovery device means an individual unit of equipment capable of and used for the purpose of recovering chemicals for use, reuse, or sale. Recovery devices include, but are not limited to, absorbers, carbon adsorbers, and condensers.

Reference control technology for gasoline loading racks means a vapor collection and processing system used to reduce emissions due to the loading of gasoline cargo tanks to 10 milligrams of total organic compounds per liter of gasoline loaded or less.

Reference control technology for marine vessels means a vapor collection system and a control device that reduces captured HAP emissions by 97 percent.

Reference control technology for miscellaneous process vents means a combustion device used to reduce organic HAP emissions by 98 percent, or to an outlet concentration of 20 parts per million by volume.

Reference control technology for storage vessels means either:

- (1) An internal floating roof meeting the specifications of § 63.119(b) of subpart G except for § 63.119 (b)(5) and (b)(6);
- (2) An external floating roof meeting the specifications of § 63.119(c) of subpart G except for § 63.119(c)(2);
- (3) An external floating roof converted to an internal floating roof meeting the specifications of § 63.119(d) of subpart G except for § 63.119(d)(2); or
- (4) A closed-vent system to a control device that reduces organic HAP emissions by 95-percent, or to an outlet concentration of 20 parts per million by volume.

(5) For purposes of emissions averaging, these four technologies are considered equivalent.

Reference control technology for wastewater means the use of:

- (1) Controls specified in §§ 61.343 through 61.347 of subpart FF of part 61;
- (2) A treatment process that achieves the emission reductions specified in table 7 of this subpart for each individual HAP present in the wastewater stream or is a steam stripper

that meets the specifications in § 63.138(g) of subpart G of this part; and

(3) A control device to reduce by 95 percent (or to an outlet concentration of 20 parts per million by volume for combustion devices) the organic HAP emissions in the vapor streams vented from treatment processes (including the steam stripper described in paragraph (2) of this definition) managing wastewater.

Refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Research and development facility means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and is not engaged in the manufacture of products for commercial sale, except in a de minimis manner.

Storage vessel means a tank or other vessel that is used to store organic liquids that are in organic HAP service. Storage vessel does not include:

- (1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;
- (2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
- (3) Vessels with capacities smaller than 40 cubic meters;
- (4) Bottoms receiver tanks; or
- (5) Wastewater storage tanks.

Wastewater storage tanks are covered under the wastewater provisions.

Temperature monitoring device means a unit of equipment used to monitor temperature and having an accuracy of ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 0.5 °C), whichever is greater.

Total annual benzene means the total amount of benzene in waste streams at a facility on an annual basis as determined in § 61.342 of 40 CFR part 61, subpart FF.

Total organic compounds or TOC, as used in this subpart, means those compounds excluding methane and ethane measured according to the procedures of Method 18 of 40 CFR part 60, appendix A. Method 25A may be used alone or in combination with Method 18 to measure TOC as provided in § 63.645 of this subpart.

Wastewater means water or wastewater that, during production or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, byproduct, or waste product and is discharged into any individual drain system. Examples are feed tank drawdown; water formed during a chemical reaction or used as a reactant; water used to wash impurities from organic products or reactants; water used to cool or quench organic vapor streams through direct contact; and condensed steam from jet ejector systems pulling vacuum on vessels containing organics.

§ 63.642 General standards.

(a) Each owner or operator of a source subject to this subpart is required to apply for a part 70 or part 71 operating permit from the appropriate permitting authority. If the EPA has approved a State operating permit program under part 70, the permit shall be obtained from the State authority. If the State operating permit program has not been approved, the source shall apply to the EPA Regional Office pursuant to part 71.

(b) [Reserved]

(c) Table 6 of this subpart specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of sources subject to this subpart.

(d) Initial performance tests and initial compliance determinations shall be required only as specified in this subpart.

(1) Performance tests and compliance determinations shall be conducted according to the schedule and procedures specified in this subpart.

(2) The owner or operator shall notify the Administrator of the intention to conduct a performance test at least 30 days before the performance test is scheduled.

(3) Performance tests shall be conducted according to the provisions of § 63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, an owner or operator shall operate the control device at either maximum or minimum representative operating conditions for monitored control device

parameters, whichever results in lower emission reduction.

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

(e) Each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed. Records for the most recent 2 years shall be retained onsite at the source or shall be accessible from a central location by computer. The remaining 3 years of records may be retained offsite. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(f) All reports required under this subpart shall be sent to the Administrator at the addresses listed in § 63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

(g) The owner or operator of an existing source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the following equation:

$$E_A = 0.02\Sigma EPV_1 + \Sigma EPV_2 + 0.025\Sigma ES_1 + \Sigma ES_2 + \Sigma EGLR_{1C} + \Sigma EGLR_2 + (R)\Sigma EMV_1 + \Sigma EMV_2 + \Sigma EWW_{1C} + \Sigma EWW_2$$

where:

E_A =Emission rate, megagrams per year, allowed for the source.

$0.02\Sigma EPV_1$ =Sum of the residual emissions, megagrams per year, from all Group 1 miscellaneous process vents, as defined in § 63.641.

ΣEPV_2 =Sum of the emissions, megagrams per year, from all Group 2 process vents, as defined in § 63.641.

$0.05\Sigma ES_1$ =Sum of the residual emissions, megagrams per year, from all Group 1 storage vessels, as defined in § 63.641.

ΣES_2 =Sum of the emissions, megagrams per year, from all Group 2 storage vessels, as defined in § 63.641.

$\Sigma EGLR_{1C}$ =Sum of the residual emissions, megagrams per year, from all Group 1 gasoline loading racks, as defined in § 63.641.

$\Sigma EGLR_2$ =Sum of the emissions, megagrams per year, from all Group 2 gasoline loading racks, as defined in § 63.641.

(R) ΣEMV_1 =Sum of the residual emissions, megagrams per year, from all Group 1 marine tank vessels, as defined in § 63.641.

$R=0.03$ for existing sources, 0.02 for new sources except offshore loading terminals, and 0.05 for new offshore loading terminals.

ΣEMV_2 =Sum of the emissions, megagrams per year, from all Group 2 marine tank vessels, as defined in § 63.641.

ΣEWW_{1C} =Sum of the residual emissions from all Group 1 wastewater streams, as defined in § 63.641. This term is calculated for each Group 1 stream according to the equation for EWW_{1C} in § 63.652(h)(6).

ΣEWW_2 =Sum of emissions from all Group 2 wastewater streams, as defined in § 63.641.

The emissions level represented by this equation is dependent on the collection of emission points in the source. The level is not fixed and can change as the emissions from each emission point change or as the number of emission points in the source change.

(h) The owner or operator of a new source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of this section.

(i) The owner or operator of an existing source shall demonstrate compliance with the emission standard in paragraph (g) of this section by following the procedures specified in paragraph (k) of this section for all emission points, or by following the emissions averaging compliance approach specified in paragraph (l) of this section for specified emission points and the procedures specified in paragraph (k) of this section for all other emission points within the source.

(j) The owner or operator of a new source shall demonstrate compliance with the emission standard in paragraph (h) of this section only by following the procedures in paragraph (k) of this section. The owner or operator of a new source may not use the emissions averaging compliance approach.

(k) The owner or operator of an existing source may comply, and the owner or operator of a new source shall comply, with the miscellaneous process vent provisions in §§ 63.643 through 63.645, the storage vessel provisions in § 63.646, the wastewater provisions in § 63.647, the gasoline loading rack provisions in § 63.650, and the marine

tank vessel loading operation provisions in § 63.651 of this subpart.

(1) The owner or operator using this compliance approach shall also comply with the requirements of § 63.654 as applicable.

(2) The owner or operator using this compliance approach is not required to calculate the annual emission rate specified in paragraph (g) of this section.

(l) The owner or operator of an existing source may elect to control some of the emission points within the source to different levels than specified under §§ 63.643 through 63.647, §§ 63.650 and 63.651 by using an emissions averaging compliance approach as long as the overall emissions for the source do not exceed the emission level specified in paragraph (g) of this section. The owner or operator using emissions averaging shall meet the requirements in paragraphs (l)(1) and (l)(2) of this section.

(1) Calculate emission debits and credits for those emission points involved in the emissions average according to the procedures specified in § 63.652; and

(2) Comply with the requirements of §§ 63.652, 63.653, and 63.654, as applicable.

(m) A State may restrict the owner or operator of an existing source to using only the procedures in paragraph (k) of this section to comply with the emission standard in paragraph (g) of this section. Such a restriction would preclude the source from using an emissions averaging compliance approach.

§ 63.643 Miscellaneous process vent provisions.

(a) The owner or operator of a Group 1 miscellaneous process vent as defined in § 63.641 shall comply with the requirements of either paragraphs (a)(1) or (a)(2) of this section.

(1) Reduce emissions of organic HAP's using a flare that meets the requirements of § 63.11(b) of subpart A of this part.

(2) Reduce emissions of organic HAP's, using a control device, by 98 weight-percent or to a concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent. Compliance can be determined by measuring either organic HAP's or TOC's using the procedures in § 63.645.

(b) If a boiler or process heater is used to comply with the percentage of reduction requirement or concentration limit specified in paragraph (a)(2) of this section, then the vent stream shall be introduced into the flame zone of such

a device, or in a location such that the required percent reduction or concentration is achieved. Testing and monitoring is required only as specified in § 63.644(a) and § 63.645 of this subpart.

§ 63.644 Monitoring provisions for miscellaneous process vents.

(a) Except as provided in paragraph (b) of this section, each owner or operator of a Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in § 63.643(a) shall install the monitoring equipment specified in paragraph (a)(1), (a)(2), (a)(3), or (a)(4) of this section, depending on the type of combustion device used. All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications.

(1) Where an incinerator is used, a temperature monitoring device equipped with a continuous recorder is required.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox or in the ductwork immediately downstream of the firebox in a position before any substantial heat exchange occurs.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) Where a flare is used, a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) capable of continuously detecting the presence of a pilot flame is required.

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

(4) Any boiler or process heater less than 44 megawatts design heat capacity where the vent stream is not introduced into the flame zone is required to use a temperature monitoring device in the firebox equipped with a continuous recorder.

(b) An owner or operator of a Group 1 miscellaneous process vent may request approval to monitor parameters other than those listed in paragraph (a) of this section. The request shall be submitted according to the procedures specified in § 63.654(h). Approval shall be requested if the owner or operator:

(1) Uses a control device other than an incinerator, boiler, process heater, or flare; or

(2) Uses one of the control devices listed in paragraph (a) of this section, but seeks to monitor a parameter other than those specified in paragraph (a) of this section.

(c) The owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with paragraph (a) of this section shall comply with either paragraph (c)(1) or (c)(2) of this section. Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, pressure relief valves needed for safety reasons, and equipment subject to § 63.648 are not subject to this paragraph.

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether a vent stream flow is present at least once every hour. Records shall be generated as specified in § 63.654(h) and (i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

(2) Secure the bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(d) The owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in § 63.654(f)(1)(ii) shall be submitted in the Notification of Compliance Status report.

(e) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of this section. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in § 63.654(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

§ 63.645 Test methods and procedures for miscellaneous process vents.

(a) To demonstrate compliance with § 63.643, an owner or operator shall follow § 63.116 except for § 63.116(d) and (e) of subpart G of this part except

as provided in paragraphs (b) through (d) of this section.

(b) All references to § 63.113(a)(1) or (a)(2) in § 63.116 of subpart G of this part shall be replaced with § 63.643(a)(1) or (a)(2), respectively.

(c) In § 63.116(c)(4)(ii)(C) of subpart G of this part, organic HAP's in the list of HAP's in table 1 of this subpart shall be considered instead of the organic HAP's in table 2 of subpart F of this part.

(d) All references to § 63.116(b)(1) or (b)(2) shall be replaced with paragraphs (d)(1) and (d)(2) of this section, respectively.

(1) Any boiler or process heater with a design heat input capacity of 44 megawatts or greater.

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

(e) For purposes of determining the TOC emission rate, as specified under paragraph (f) of this section, the sampling site shall be after the last product recovery device (as defined in § 63.641 of this subpart) (if any recovery devices are present) but prior to the inlet of any control device (as defined in § 63.641 of this subpart) that is present, prior to any dilution of the process vent stream, and prior to release to the atmosphere.

(1) Methods 1 or 1A of 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling site.

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

(f) Except as provided in paragraph (g) of this section, an owner or operator seeking to demonstrate that a process vent TOC mass flow rate is less than 33 kilograms per day for an existing source or less than 6.8 kilograms per day for a new source in accordance with the Group 2 process vent definition of this subpart shall determine the TOC mass flow rate by the following procedures:

(1) The sampling site shall be selected as specified in paragraph (e) of this section.

(2) The gas volumetric flow rate shall be determined using Methods 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate.

(3) Method 18 or Method 25A of 40 CFR part 60, appendix A shall be used to measure concentration; alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part may be used. If Method 25A is used, and the TOC mass flow rate calculated from the Method 25A measurement is greater than or equal to 33 kilograms per day for an existing source or 6.8 kilograms per day for a new source, Method 18 may be used to determine

any non-VOC hydrocarbons that may be deducted to calculate the TOC (minus non-VOC hydrocarbons) concentration and mass flow rate. The following procedures shall be used to calculate parts per million by volume concentration:

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

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

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

where:

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

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

n=Number of components in the sample.

x=Number of samples in the sample run.

(4) The emission rate of TOC (minus methane and ethane) (E_{TOC}) shall be calculated using the following equation if Method 18 is used:

$$E = K_2 \left[\sum_{j=1}^n C_j M_j \right] Q_s$$

where:

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

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

C_j =Concentration on a dry basis of organic compound j in parts per million as measured by Method 18 of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section. C_j includes all organic compounds measured minus methane and ethane.

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

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

(5) If Method 25A is used the emission rate of TOC (E_{TOC}) shall be calculated using the following equation:

$$E = K_2 C_{TOC} Q_s$$

where:

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

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

C_{TOC} =Concentration of TOC on a dry basis in parts per million volume as measured by Method 25A of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section.

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

(g) Engineering assessment may be used to determine the TOC emission rate for the representative operating condition expected to yield the highest daily emission rate.

(1) Engineering assessment includes, but is not limited to, the following:

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

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

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

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

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

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

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

(v) All data, assumptions, and procedures used in the engineering assessment shall be documented.

(h) The owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. Examples of process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph, process changes do not

include: process upsets; unintentional, temporary process changes; and changes that are within the range on which the original calculation was based.

(1) The TOC emission rate shall be recalculated based on measurements of vent stream flow rate and TOC as specified in paragraphs (e) and (f) of this section, as applicable, or on best engineering assessment of the effects of the change. Engineering assessments shall meet the specifications in paragraph (g) of this section.

(2) Where the recalculated TOC emission rate is greater than 33 kilograms per day for an existing source or greater than 6.8 kilograms per day for a new source, the owner or operator shall submit a report as specified in § 63.654 (c), (d), (e), (f), or (g), or (h) and shall comply with the appropriate provisions in § 63.643 by the dates specified in § 63.640.

§ 63.646 Storage vessel provisions.

(a) Each owner or operator of a Group 1 storage vessel subject to this subpart shall comply with the requirements of §§ 63.119 through 63.121 of subpart G of this part except as provided in paragraphs (b) through (m) of this section.

(b) As used in this section, all terms not defined in § 63.641 shall have the meaning given them in 40 CFR part 63, subparts A or G. The Group 1 storage vessel definition presented in § 63.641 shall apply in lieu of the Group 1 storage vessel definitions presented in tables 5 and 6 of § 63.119 of subpart G of this part.

(1) An owner or operator may use good engineering judgement or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(2) When an owner or operator and the Administrator do not agree on whether the weight percent organic HAP in the stored liquid is above or below 4 percent for existing sources and 2 percent for new sources, Method 18 of 40 CFR part 60, appendix A shall be used.

(c) The following paragraphs do not apply to storage vessels at existing sources subject to this subpart: § 63.119 (b)(5), (b)(6), (c)(2), and (d)(2).

(d) References shall be replaced as specified in paragraphs (d)(1) through (d)(9) of this section.

(1) All references to § 63.100(k) of subpart F of this part (or the schedule provisions and the compliance date) shall be replaced with § 63.640(h).

(2) All references to April 22, 1994 shall be replaced with August 18, 1995.

(3) All references to December 31, 1992 shall be replaced with July 15, 1994.

(4) All references to the compliance dates specified in § 63.100 of subpart F shall be replaced with § 63.640 (h) through (m).

(5) All references to § 63.150 in § 63.119 of subpart G of this part shall be replaced with § 63.652.

(6) All references to § 63.113(a)(2) of subpart G shall be replaced with § 63.643(a)(2) of this subpart.

(7) All references to § 63.126(b)(1) of subpart G shall be replaced with § 63.422(b) of subpart R of this part.

(8) All references to § 63.128(a) of subpart G shall be replaced with § 63.425, paragraphs (a) through (c) and (e) through (h) of subpart R of this part.

(9) All references to § 63.139(d)(1) in § 63.120(d)(1)(iii) of subpart G shall be replaced with § 61.355 of subpart FF of part 61.

(e) When complying with the inspection requirements of § 63.120 of subpart G of this part, owners and operators of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.

(f) The following paragraphs (f)(1), (f)(2), and (f)(3) of this section apply to Group 1 storage vessels at existing sources:

(1) If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

(2) Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

(3) Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(g) Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

(h) References in §§ 63.119 through 63.121 to § 63.122(g)(1), § 63.151, and references to initial notification requirements do not apply.

(i) References to the Implementation Plan in § 63.120, paragraphs (d)(2) and (d)(3)(i) shall be replaced with the Notification of Compliance Status report.

(j) References to the Notification of Compliance Status report in § 63.152(b) shall be replaced with § 63.654(f).

(k) References to the Periodic Reports in § 63.152(c) shall be replaced with § 63.654(g).

(l) The State or local permitting authority can waive the notification requirements of §§ 63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii) for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in §§ 63.120(a)(6) or 63.120(b)(10)(iii) for all storage vessels at a refinery or for individual storage vessels on a case-by-case basis.

§ 63.647 Wastewater provisions.

(a) Except as provided in paragraph (b) of this section, each owner or operator of a Group 1 wastewater stream shall comply with the requirements of §§ 61.340 through 61.355 of 40 CFR part 61, subpart FF for each process wastewater stream that meets the definition in § 63.641.

(b) As used in this section, all terms not defined in § 63.641 shall have the meaning given them in the Clean Air Act or in 40 CFR part 61, subpart FF, § 61.341.

(c) Each owner or operator required under subpart FF of 40 CFR part 61 to perform periodic measurement of benzene concentration in wastewater, or to monitor process or control device operating parameters shall operate in a manner consistent with the minimum or maximum (as appropriate) permitted concentration or operating parameter values. Operation of the process, treatment unit, or control device resulting in a measured concentration or operating parameter value outside the permitted limits shall constitute a violation of the emission standards. Failure to perform required leak monitoring for closed vent systems and control devices or failure to repair leaks within the time period specified in subpart FF of 40 CFR part 61 shall constitute a violation of the standard.

§ 63.648 Equipment leak standards.

(a) Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60 subpart VV and paragraph (b) of this section except as provided in paragraphs (a)(1), (a)(2), and (c) through (i) of this section. Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in paragraphs (c) through (i) of this section.

(1) For purposes of compliance with this section, the provisions of 40 CFR part 60, subpart VV apply only to equipment in organic HAP service, as defined in § 63.641 of this subpart.

(2) Calculation of percentage leaking equipment components for subpart VV of 40 CFR part 60 may be done on a process unit basis or a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(b) The use of monitoring data generated before August 18, 1995 to qualify for less frequent monitoring of valves and pumps as provided under 40 CFR part 60 subpart VV or subpart H of this part and paragraph (c) of this section (i.e., quarterly or semiannually) is governed by the requirements of paragraphs (b)(1) and (b)(2) of this section.

(1) Monitoring data must meet the test methods and procedures specified in § 60.485(b) of 40 CFR part 60, subpart VV or § 63.180(b)(1) through (b)(5) of subpart H of this part except for minor departures.

(2) Departures from the criteria specified in § 60.485(b) of 40 CFR part 60 subpart VV or § 63.180(b)(1) through (b)(5) of subpart H of this part or from the monitoring frequency specified in subpart VV or in paragraph (c) of this section (such as every 6 weeks instead of monthly or quarterly) are minor and do not significantly affect the quality of the data. An example of a minor departure is monitoring at a slightly different frequency (such as every 6 weeks instead of monthly or quarterly). Failure to use a calibrated instrument is not considered a minor departure.

(c) In lieu of complying with the existing source provisions of paragraph (a) in this section, an owner or operator may elect to comply with the requirements of §§ 63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H of this part except as provided in paragraphs (c)(1) through (c)(10) and (e) through (i) of this section.

(1) The instrument readings that define a leak for light liquid pumps subject to § 63.163 of subpart H of this part and gas/vapor and light liquid valves subject to § 63.168 of subpart H of this part are specified in table 2 of this subpart.

(2) In phase III of the valve standard, the owner or operator may monitor valves for leaks as specified in paragraphs (c)(2)(i) or (c)(2)(ii) of this section.

(i) If the owner or operator does not elect to monitor connectors, then the owner or operator shall monitor valves according to the frequency specified in table 8 of this subpart.

(ii) If an owner or operator elects to monitor connectors according to the provisions of § 63.649, paragraphs (b),

(c), or (d), then the owner or operator shall monitor valves at the frequencies specified in table 9 of this subpart.

(3) The owner or operator shall decide no later than the first required monitoring period after the phase I compliance date specified in § 63.640(h) whether to calculate the percentage leaking valves on a process unit basis or on a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(4) The owner or operator shall decide no later than the first monitoring period after the phase III compliance date specified in § 63.640(h) whether to monitor connectors according to the provisions in § 63.649, paragraphs (b), (c), or (d).

(5) Connectors in gas/vapor service or light liquid service are subject to the requirements for connectors in heavy liquid service in § 63.169 of subpart H of this part (except for the agitator provisions). The leak definition for valves, connectors, and instrumentation systems subject to § 63.169 is 1,000 parts per million.

(6) In phase III of the pump standard, except as provided in paragraph (c)(7) of this section, owners or operators that achieve less than 10 percent of light liquid pumps leaking or three light liquid pumps leaking, whichever is greater, shall monitor light liquid pumps monthly.

(7) Owners or operators that achieve less than 3 percent of light liquid pumps leaking or one light liquid pump leaking, whichever is greater, shall monitor light liquid pumps quarterly.

(8) An owner or operator may make the election described in paragraphs (c)(3) and (c)(4) of this section at any time except that any election to change after the initial election shall be treated as a permit modification according to the terms of part 70 of this chapter.

(9) When complying with the requirements of § 63.138(e)(3)(i) of subpart H of this part, non-repairable valves shall be included in the calculation of percent leaking valves the first time the valve is identified as leaking and non-repairable. Otherwise, a number of non-repairable valves up to a maximum of 1 percent per year of the total number of valves in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percent leaking valves for subsequent monitoring periods. When the number of non-repairable valves exceeds 3 percent of the total number of valves in organic HAP service, the number of non-repairable valves exceeding 3 percent of the total number shall be

included in the calculation of percent leaking valves.

(10) If in phase III of the valve standard any valve is designated, as described in 40 CFR 60.4685(e)(2), as having no detectable emissions the owner or operator has the option of following the provisions of § 60.482-7(f) of subpart VV of part 60. If an owner or operator chooses to comply with the provisions of 40 CFR 60.482-7(f), the valve is exempt from the valve monitoring provisions of § 63.168 of subpart H of this part.

(d) Upon startup of new sources, the owner or operator shall comply with § 63.163(a)(1)(ii) of subpart H of this part for light liquid pumps and § 63.168(a)(1)(ii) of subpart H of this part for gas/vapor and light liquid valves.

(e) For reciprocating pumps in heavy liquid service, owners and operators are not required to comply with the requirements in § 63.169 of subpart H of this part.

(f) Reciprocating pumps in light liquid service are exempt from §§ 63.163 and 60.482 if recasting the distance piece or reciprocating pump replacement is required.

(g) Compressors in hydrogen service are exempt from the requirements of paragraphs (a) and (c) of this section if an owner or operator demonstrates that a compressor is in hydrogen service.

(1) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service.

(2) For a piece of equipment to be considered in hydrogen service, it must be determined that the percentage hydrogen content can be reasonably expected always to exceed 50 percent by volume.

(i) For purposes of determining the percentage hydrogen content in the process fluid that is contained in or contacts a compressor, the owner or operator shall use either:

(A) Procedures that conform to those specified in § 60.593(b)(2) of 40 part 60, subpart GGG.

(B) Engineering judgment to demonstrate that the percentage content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume.

(1) When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, the procedures in paragraph (g)(2)(i)(A) of this section shall be used to resolve the disagreement.

(2) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only by following the procedures in paragraph (g)(2)(i)(A) of this section.

(h) Each owner or operator of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years.

(i) Reciprocating compressors are exempt from seal requirements if recasting the distance piece or compressor replacement is required.

§ 63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

(a) If an owner or operator elects to monitor valves according to the provisions of § 63.648(c)(2)(ii), the owner or operator shall implement one of the connector monitoring programs specified in paragraphs (b), (c), or (d) of this section.

(b) *Random 200 connector alternative.* The owner or operator shall implement a random sampling program for accessible connectors of 2.0 inches nominal diameter or greater. The program does not apply to inaccessible or unsafe-to-monitor connectors, as defined in § 63.174 of subpart H. The sampling program shall be implemented source-wide.

(1) Within the first 12 months after the phase III compliance date specified in § 63.640(h), a sample of 200 connectors shall be randomly selected and monitored using Method 21 of 40 CFR part 60, appendix A.

(2) The instrument reading that defines a leak is 1,000 parts per million.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, the connector shall be monitored for leaks within the first 3 months after its repair.

(5) After conducting the initial survey required in paragraph (b)(1) of this section, the owner or operator shall conduct subsequent monitoring of connectors at the frequencies specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall survey a random sample of 200 connectors once every 6 months.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or

operator shall survey a random sample of 200 connectors once per year.

(iii) If the percentage leaking connectors is 0.5 percent or greater but less than 1.0 percent, the owner or operator shall survey a random sample of 200 connectors once every 2 years.

(iv) If the percentage leaking connectors is less than 0.5 percent, the owner or operator shall survey a random sample of 200 connectors once every 4 years.

(6) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(c) *Connector inspection alternative.* The owner or operator shall implement a program to monitor all accessible connectors in gas/vapor service that are 2.0 inches (nominal diameter) or greater and inspect all accessible connectors in light liquid service that are 2 inches (nominal diameter) or greater as described in paragraphs (c)(1) through (c)(7) of this section. The program does not apply to inaccessible or unsafe-to-monitor connectors.

(1) Within 12 months after the phase III compliance date specified in § 63.640(h), all connectors in gas/vapor service shall be monitored using Method 21 of 40 CFR part 60 appendix A. The instrument reading that defines a leak is 1,000 parts per million.

(2) All connectors in light liquid service shall be inspected for leaks. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, connectors in gas/vapor service shall be monitored for leaks within the first 3 months after repair. Connectors in light liquid service shall be inspected for indications of leaks within the first 3 months after repair. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(5) After conducting the initial survey required in paragraphs (c)(1) and (c)(2) of this section, the owner or operator shall conduct subsequent monitoring at the frequencies specified in paragraphs (c)(5)(i) through (c)(5)(iii) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall monitor or

inspect, as applicable, the connectors once per year.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 2 years.

(iii) If the percentage leaking connectors is less than 1.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 4 years.

(6) The percentage leaking connectors shall be calculated for connectors in gas/vapor service and for connectors in light liquid service. The data for the two groups of connectors shall not be pooled for the purpose of determining the percentage leaking connectors.

(i) The percentage leaking connectors shall be calculated as follows:

$$\% C_L = [(C_L - C_{AN}) / (C_L + C_e)] \times 100$$

where:

$\% C_L$ = Percentage leaking connectors.

C_L = Number of connectors including nonreparables, measured at 1,000 parts per million or greater, by Method 21 of 40 CFR part 60, Appendix A.

C_{AN} = Number of allowable nonreparable connectors, as determined by monitoring, not to exceed 3 percent of the total connector population, C_L .

C_e = Total number of monitored connectors, including nonreparables, in the process unit.

C_e = Optional credit for removed connectors = $0.67 \times \text{net number}$ (i.e., the total number of connectors removed minus the total added) of connectors in organic HAP service removed from the process unit after the applicability date set forth in § 63.640(h)(4)(iii) for existing process units, and after the date of start-up for new process units. If credits are not taken, then $C_e = 0$.

(ii) Nonreparable connectors shall be included in the calculation of percentage leaking connectors the first time the connector is identified as leaking and nonreparable. Otherwise, a number of nonreparable connectors up to a maximum of 1 percent per year of the total number of connectors in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percentage leaking connectors for subsequent monitoring periods.

(iii) If the number of nonreparable connectors exceeds 3 percent of the total number of connectors in organic HAP service, the number of nonreparable connectors exceeding 3 percent of the total number shall be included in the

calculation of the percentage leaking connectors.

(7) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(d) *Subpart H program.* The owner or operator shall implement a program to comply with the provisions in § 63.174 of this part.

(e) Delay of repair of connectors for which leaks have been detected is allowed if repair is not technically feasible by normal repair techniques without a process unit shutdown. Repair of this equipment shall occur by the end of the next process unit shutdown.

(1) Delay of repair is allowed for equipment that is isolated from the process and that does not remain in organic HAP service.

(2) Delay of repair for connectors is also allowed if:

(i) The owner or operator determines that emissions of purged material resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, and

(ii) When repair procedures are accomplished, the purged material would be collected and destroyed or recovered in a control device.

(f) Any connector that is designated as an unsafe-to-repair connector is exempt from the requirements of paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), or (d) of this section if:

(1) The owner or operator determines that repair personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), of this section; or

(2) The connector will be repaired before the end of the next scheduled process unit shutdown.

(g) The owner or operator shall maintain records to document that the connector monitoring or inspections have been conducted as required and to document repair of leaking connectors as applicable.

§ 63.650 Gasoline loading rack provisions.

(a) Except as provided in paragraphs (b) through (c) of this section, each owner or operator of a gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with subpart R, §§ 63.421, 63.422(a) through (d), 63.425(a) through (c), 63.425(e) through (h), 63.427(a) and (b), and

63.428(b), (c), (g)(1), and (h)(1) through (h)(3).

(b) As used in this section, all terms not defined in § 63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart R. The § 63.641 definition of "affected source" applies under this section.

(c) Gasoline loading racks regulated under this subpart are subject to the compliance dates specified in § 63.640(h).

§ 63.651 Marine tank vessel loading operation provisions.

(a) Except as provided in paragraphs (b) through (c) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§ 63.560 through 63.567 of 40 CFR part 63, subpart Y.

(b) As used in this section, all terms not defined in § 63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart Y. The § 63.641 definition of "affected source" applies under this section.

(c) The Initial Notification Report under § 63.567(b) is not required.

§ 63.652 Emissions averaging provisions.

(a) This section applies to owners or operators of existing sources who seek to comply with the emission standard in § 63.642(g) by using emissions averaging according to § 63.642(l) rather than following the provisions of §§ 63.643 through 63.647, and §§ 63.650 and 63.651. Existing marine tank vessel loading operations unable to comply with the standard by using emissions averaging are those marine tank vessels subject to 40 CFR 63.562(e) of this part and the Valdez Marine Terminal source.

(b) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in § 63.653(d) for all points to be included in an emissions average. The Implementation Plan shall identify all emission points to be included in the emissions average. This must include any Group 1 emission points to which the reference control technology (defined in § 63.641) is not applied and all other emission points being controlled as part of the average.

(c) The following emission points can be used to generate emissions averaging credits if control was applied after November 15, 1990 and if sufficient information is available to determine the appropriate value of credits for the emission point:

- (1) Group 2 emission points;
- (2) Group 1 storage vessels, Group 1 wastewater streams, Group 1 gasoline

loading racks, Group 1 marine tank vessels, and Group 1 miscellaneous process vents that are controlled by a technology that the Administrator or permitting authority agrees has a higher nominal efficiency than the reference control technology. Information on the nominal efficiencies for such technologies must be submitted and approved as provided in paragraph (i) of this section; and

(3) Emission points from which emissions are reduced by pollution prevention measures. Percentages of reduction for pollution prevention measures shall be determined as specified in paragraph (j) of this section.

(i) For a Group 1 emission point, the pollution prevention measure must reduce emissions more than the reference control technology would have had the reference control technology been applied to the emission point instead of the pollution prevention measure except as provided in paragraph (c)(3)(ii) of this section.

(ii) If a pollution prevention measure is used in conjunction with other controls for a Group 1 emission point, the pollution prevention measure alone does not have to reduce emissions more than the reference control technology, but the combination of the pollution prevention measure and other controls must reduce emissions more than the reference control technology would have had it been applied instead.

(d) The following emission points cannot be used to generate emissions averaging credits:

(1) Emission points already controlled on or before November 15, 1990 unless the level of control is increased after November 15, 1990, in which case credit will be allowed only for the increase in control after November 15, 1990;

(2) Group 1 emission points that are controlled by a reference control technology unless the reference control technology has been approved for use in a different manner and a higher nominal efficiency has been assigned according to the procedures in paragraph (i) of this section. For example, it is not allowable to claim that an internal floating roof meeting only the specifications stated in the reference control technology definition in § 63.641 (i.e., that meets the specifications of § 63.119(b) of subpart G but does not have controlled fittings per § 63.119 (b)(5) and (b)(6) of subpart G) applied to a storage vessel is achieving greater than 95 percent control;

(3) Emission points on shutdown process units. Process units that are shut down cannot be used to generate credits or debits;

(4) Wastewater that is not process wastewater or wastewater streams treated in biological treatment units. These two types of wastewater cannot be used to generate credits or debits. Group 1 wastewater streams cannot be left undercontrolled or uncontrolled to generate debits. For the purposes of this section, the terms "wastewater" and "wastewater stream" are used to mean process wastewater; and

(5) Emission points controlled to comply with a State or Federal rule other than this subpart, unless the level of control has been increased after November 15, 1990 above what is required by the other State or Federal rule. Only the control above what is required by the other State or Federal rule will be credited. However, if an emission point has been used to generate emissions averaging credit in an approved emissions average, and the point is subsequently made subject to a State or Federal rule other than this subpart, the point can continue to generate emissions averaging credit for the purpose of complying with the previously approved average.

(e) For all points included in an emissions average, the owner or operator shall:

(1) Calculate and record monthly debits for all Group 1 emission points that are controlled to a level less stringent than the reference control technology for those emission points. Equations in paragraph (g) of this section shall be used to calculate debits.

(2) Calculate and record monthly credits for all Group 1 or Group 2 emission points that are overcontrolled to compensate for the debits. Equations in paragraph (h) of this section shall be used to calculate credits. Emission points and controls that meet the criteria of paragraph (c) of this section may be included in the credit calculation, whereas those described in paragraph (d) of this section shall not be included.

(3) Demonstrate that annual credits calculated according to paragraph (h) of this section are greater than or equal to debits calculated for the same annual compliance period according to paragraph (g) of this section.

(i) The initial demonstration in the Implementation Plan that credit-generating emission points will be capable of generating sufficient credits to offset the debits from the debit-generating emission points must be made under representative operating conditions.

(ii) After the compliance date, actual operating data will be used for all debit and credit calculations.

(4) Demonstrate that debits calculated for a quarterly (3-month) period according to paragraph (g) of this section are not more than 1.30 times the credits for the same period calculated according to paragraph (h) of this section. Compliance for the quarter shall be determined based on the ratio of credits and debits from that quarter, with 30 percent more debits than credits allowed on a quarterly basis.

(5) Record and report quarterly and annual credits and debits in the Periodic Reports as specified in § 63.654(g)(8). Every fourth Periodic Report shall include a certification of compliance with the emissions averaging provisions as required by § 63.654(g)(8)(iii).

(f) Debits and credits shall be calculated in accordance with the methods and procedures specified in paragraphs (g) and (h) of this section,

respectively, and shall not include emissions from the following:

(1) More than 20 individual emission points. Where pollution prevention measures (as specified in paragraph (j)(1) of this section) are used to control emission points to be included in an emissions average, no more than 25 emission points may be included in the average. For example, if two emission points to be included in an emissions average are controlled by pollution prevention measures, the average may include up to 22 emission points.

(2) Periods of startup, shutdown, and malfunction as described in the source's startup, shutdown, and malfunction plan required by § 63.6(e)(3) of subpart A of this part.

(3) For emission points for which continuous monitors are used, periods of excess emissions as defined in § 63.654(g)(6)(i). For these periods, the calculation of monthly credits and

debits shall be adjusted as specified in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

(i) No credits would be assigned to the credit-generating emission point.

(ii) Maximum debits would be assigned to the debit-generating emission point.

(iii) The owner or operator may use the procedures in paragraph (l) of this section to demonstrate to the Administrator that full or partial credits or debits should be assigned.

(g) Debits are generated by the difference between the actual emissions from a Group 1 emission point that is uncontrolled or is controlled to a level less stringent than the reference control technology, and the emissions allowed for Group 1 emission point. Debits shall be calculated as follows:

(1) The overall equation for calculating sourcewide debits is:

$$\text{Debits} = \sum_{i=1}^n (\text{EPV}_{i\text{ACTUAL}} - (0.02)\text{EPV}_{i\text{u}}) + \sum_{i=1}^n (\text{ES}_{i\text{ACTUAL}} - (0.05)\text{ES}_{i\text{u}}) + \sum_{i=1}^n (\text{EGLR}_{i\text{ACTUAL}} - \text{EGLR}_{i\text{c}}) + \sum_{i=1}^n (\text{EMV}_{i\text{ACTUAL}} - (0.03)\text{EMV}_{i\text{u}})$$

where:

Debits and all terms of the equation are in units of megagrams per month, and

$\text{EPV}_{i\text{ACTUAL}}$ =Emissions from each Group 1 miscellaneous process vent i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(2) of this section.

$(0.02)\text{EPV}_{i\text{u}}$ =Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(2) of this section.

$\text{ES}_{i\text{ACTUAL}}$ =Emissions from each Group 1 storage vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(3) of this section.

$(0.05)\text{ES}_{i\text{u}}$ =Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(3) of this section.

$\text{EGLR}_{i\text{ACTUAL}}$ =Emissions from each Group 1 gasoline loading rack i that is uncontrolled or is controlled to a level less stringent than the

reference control technology. This is calculated according to paragraph (g)(4) of this section.

$\text{EGLR}_{i\text{c}}$ =Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. This is calculated according to paragraph (g)(4) of this section.

$\text{EMV}_{i\text{ACTUAL}}$ =Emissions from each Group 1 marine tank vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(5) of this section.

$(0.03)\text{EMV}_{i\text{u}}$ =Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions calculated according to paragraph (g)(5) of this section.

n =The number of Group 1 emission points being included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

(2) Emissions from miscellaneous process vents shall be calculated as follows:

(i) For purposes of determining miscellaneous process vent stream flow rate, organic HAP concentrations, and

temperature, the sampling site shall be after the final product recovery device, if any recovery devices are present; before any control device (for miscellaneous process vents, recovery devices shall not be considered control devices); and before discharge to the atmosphere. Method 1 or 1A of part 60, appendix A shall be used for selection of the sampling site.

(ii) The following equation shall be used for each miscellaneous process vent i to calculate $\text{EPV}_{i\text{u}}$:

$$\text{EPV}_{i\text{u}} = (2.494 \times 10^{-9}) Qh \left(\sum_{j=1}^n C_j M_j \right)$$

where:

$\text{EPV}_{i\text{u}}$ =Uncontrolled process vent emission rate from miscellaneous process vent i , megagrams per month.

Q =Vent stream flow rate, dry standard cubic meters per minute, measured using Methods 2, 2A, 2C, or 2D of part 60 appendix A, as appropriate.

h =Monthly hours of operation during which positive flow is present in the vent, hours per month.

C_j =Concentration, parts per million by volume, dry basis, of organic HAP j as measured by Method 18 of part 60 appendix A.

M_j =Molecular weight of organic HAP j , gram per gram-mole.

n =Number of organic HAP's in the miscellaneous process vent stream.

(A) The values of Q , C_j , and M_j shall be determined during a performance test conducted under representative operating conditions. The values of Q , C_j , and M_j shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (g)(2)(ii)(B) of this section.

(B) If there is a change in capacity utilization other than a change in

monthly operating hours, or if any other change is made to the process or product recovery equipment or operation such that the previously measured values of Q , C_j , and M_j are no longer representative, a new performance test shall be conducted to determine new representative values of Q , C_j , and M_j . These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following procedures and equations shall be used to calculate $EPV_{iACTUAL}$:

(A) If the vent is not controlled by a control device or pollution prevention measure, $EPV_{iACTUAL} = EPV_{iu}$, where EPV_{iu} is calculated according to the procedures in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the vent is controlled using a control device or a pollution prevention measure achieving less than 98-percent reduction,

$$EPV_{iACTUAL} = EPV_{iu} \times \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

(1) The percent reduction shall be measured according to the procedures in § 63.116 of subpart G if a combustion control device is used. For a flare meeting the criteria in § 63.116(a) of subpart G, or a boiler or process heater meeting the criteria in § 63.645(d) of this subpart or § 63.116(b) of subpart G, the percentage of reduction shall be 98 percent. If a noncombustion control device is used, percentage of reduction shall be demonstrated by a performance test at the inlet and outlet of the device,

or, if testing is not feasible, by a control design evaluation and documented engineering calculations.

(2) For determining debits from miscellaneous process vents, product recovery devices shall not be considered control devices and cannot be assigned a percentage of reduction in calculating $EPV_{iACTUAL}$. The sampling site for measurement of uncontrolled emissions is after the final product recovery device.

(3) Procedures for calculating the percentage of reduction of pollution prevention measures are specified in paragraph (j) of this section.

(3) Emissions from storage vessels shall be calculated as specified in § 63.150(g)(3) of subpart G.

(4) Emissions from gasoline loading racks shall be calculated as follows:

(i) The following equation shall be used for each gasoline loading rack i to calculate $EGLR_{iu}$:

$$EGLR_{iu} = (1.20 \times 10^{-7}) \frac{SPMG}{T}$$

where:

$EGLR_{iu}$ =Uncontrolled transfer HAP emission rate from gasoline loading rack i , megagrams per month

S =Saturation factor, dimensionless (see table 33 of subpart G).

P =Weighted average rack partial pressure of organic HAP's

transferred at the rack during the month, kilopascals.

M =Weighted average molecular weight of organic HAP's transferred at the gasoline loading rack during the month, gram per gram-mole.

G =Monthly volume of gasoline transferred from gasoline loading rack, liters per month.

T =Weighted rack bulk liquid loading temperature during the month, degrees kelvin (degrees Celsius °C + 273).

(ii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack partial pressure:

$$P = \frac{\sum_{j=1}^n (P_j)(G_j)}{G}$$

where:

P_j =Maximum true vapor pressure of individual organic HAP transferred at the rack, kilopascals.

G =Monthly volume of organic HAP transferred, liters per month, and

$$G = \sum_{j=1}^n G_j$$

G_j =Monthly volume of individual organic HAP transferred at the

gasoline loading rack, liters per month.

n =Number of organic HAP's transferred at the gasoline loading rack.

(iii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack molecular weight:

$$M = \frac{\sum_{j=1}^n (M_j)(G_j)}{G}$$

where:

M_j =Molecular weight of individual organic HAP transferred at the rack, gram per gram-mole.

G , G_j , and n are as defined in paragraph (g)(4)(ii) of this section.

(iv) The following equation shall be used for each gasoline loading rack i to calculate the monthly weighted rack bulk liquid loading temperature:

$$T = \frac{\sum_{j=1}^n (T_j)(G_j)}{G}$$

T_j =Average annual bulk temperature of individual organic HAP loaded at the gasoline loading rack, kelvin (degrees Celsius $^{\circ}\text{C}+273$).

G , G_j , and n are as defined in paragraph (g)(4)(ii) of this section.

(v) The following equation shall be used to calculate EGLR_{ic} :

$$\text{EGLR}_{ic} = 1 \times 10^{-8} G$$

G is as defined in paragraph (g)(4)(ii) of this section.

(vi) The following procedures and equations shall be used to calculate $\text{EGLR}_{i\text{ACTUAL}}$:

(A) If the gasoline loading rack is not controlled, $\text{EGLR}_{i\text{ACTUAL}} = \text{EGLR}_{iu}$, where EGLR_{iu} is calculated using the equations specified in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack is controlled using a control device or a pollution prevention measure not achieving the requirement of less than 10 milligrams of TOC per liter of gasoline loaded,

$$\text{EMV}_{iu} = \sum_{i=1}^m (Q_i)(F_i)(P_i)$$

(1) The percent reduction for a control device shall be measured according to the procedures and test methods specified in § 63.128(a) of subpart G. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in § 63.128(h) of subpart G.

(2) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(5) Emissions from marine tank vessel loading shall be calculated as follows:

(i) The following equation shall be used for each marine tank vessel i to calculate EMV_{iu} :

$$\text{EMV}_{iu} = \sum_{i=1}^m (Q_i)(F_i)(P_i)$$

where:

EMV_{iu} =Uncontrolled marine tank vessel HAP emission rate from marine tank vessel i , megagrams per month.

Q_i =Quantity of commodity loaded (per vessel type), liters.

F_i =Emission factor, megagrams per liter.

P_i =Percent HAP.

m =Number of combinations of commodities and vessel types loaded.

Emission factors shall be based on test data or emission estimation procedures specified in § 63.565(l) of subpart Y.

(ii) The following procedures and equations shall be used to calculate $\text{EMV}_{i\text{ACTUAL}}$:

(A) If the marine tank vessel is not controlled, $\text{EMV}_{i\text{ACTUAL}} = \text{EMV}_{iu}$, where EMV_{iu} is calculated using the equations specified in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel is controlled using a control device or a pollution prevention measure achieving less than 97-percent reduction,

$$\text{EMV}_{i\text{ACTUAL}} = \text{EMV}_{iu} \left(\frac{1 - \text{Percent reduction}}{100\%} \right)$$

(1) The percent reduction for a control device shall be measured according to the procedures and test methods specified in § 63.565(c) of subpart Y. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in § 63.128(h) of subpart G.

(2) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(h) Credits are generated by the difference between emissions that are allowed for each Group 1 and Group 2 emission point and the actual emissions from a Group 1 or Group 2 emission

point that has been controlled after November 15, 1990 to a level more stringent than what is required by this subpart or any other State or Federal rule or statute. Credits shall be calculated as follows:

(1) The overall equation for calculating sourcewide credits is:

$$\begin{aligned} \text{Credits} = & D \sum_{i=1}^n ((0.02) \text{EPV1}_{iu} - \text{EPV1}_{i\text{ACTUAL}}) + D \sum_{i=1}^m (\text{EPV2}_{i\text{BASE}} - \text{EPV2}_{i\text{ACTUAL}}) + D \sum_{i=1}^n ((0.05) \text{ES1}_{iu} - \text{ES1}_{i\text{ACTUAL}}) \\ & + D \sum_{i=1}^m (\text{ES2}_{i\text{BASE}} - \text{ES2}_{i\text{ACTUAL}}) + D \sum_{i=1}^n (\text{EGLR}_{ic} - \text{EGLR1}_{i\text{ACTUAL}}) + D \sum_{i=1}^m (\text{EGLR2}_{i\text{BASE}} - \text{EGLR2}_{i\text{ACTUAL}}) \\ & + D \sum_{i=1}^n ((0.03) \text{EMV1}_{iu} - \text{EMV1}_{i\text{ACTUAL}}) + D \sum_{i=1}^m (\text{EMV2}_{i\text{BASE}} - \text{EMV2}_{i\text{ACTUAL}}) + D \sum_{i=1}^n (\text{EWW1}_{ic} - \text{EWW1}_{i\text{ACTUAL}}) \\ & + D \sum_{i=1}^m (\text{EWW2}_{i\text{BASE}} - \text{EWW2}_{i\text{ACTUAL}}) \end{aligned}$$

where:

Credits and all terms of the equation are in units of megagrams per month, the baseline date is November 15, 1990, and

D=Discount factor=0.9 for all credit-generating emission points except those controlled by a pollution prevention measure, which will not be discounted.

EPV1_{iACTUAL}=Emissions from each Group 1 miscellaneous process vent i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(2) of this section.

(0.02) EPV1_{iu}=Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions. EPV1_{iu} is calculated according to paragraph (h)(2) of this section.

EPV2_{iBASE}=Emissions from each Group 2 miscellaneous process vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

EPV2_{iACTUAL}=Emissions from each Group 2 miscellaneous process vent that is controlled, calculated according to paragraph (h)(2) of this section.

ES1_{iACTUAL}=Emissions from each Group 1 storage vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(3) of this section.

(0.05) ES1_{iu}=Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions. ES1_{iu} is calculated according to paragraph (h)(3) of this section.

ES2_{iACTUAL}=Emissions from each Group 2 storage vessel i that is controlled, calculated according to paragraph (h)(3) of this section.

ES2_{iBASE}=Emissions from each Group 2 storage vessel i at the baseline date, as calculated in paragraph (h)(3) of this section.

EGLR1_{iACTUAL}=Emissions from each Group 1 gasoline loading rack i that is controlled to a level more

stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

EGLR_{iu}=Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. EGLR_{iu} is calculated according to paragraph (h)(4) of this section.

EGRL2_{iACTUAL}=Emissions from each Group 2 gasoline loading rack i that is controlled, calculated according to paragraph (h)(4) of this section.

EGLR2_{iBASE}=Emissions from each Group 2 gasoline loading rack i at the baseline date, as calculated in paragraph (h)(4) of this section.

EMV1_{iACTUAL}=Emissions from each Group 1 marine tank vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

(0.03) EMV1_{iu}=Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions. EMV1_{iu} is calculated according to paragraph (h)(5) of this section.

EMV2_{iACTUAL}=Emissions from each Group 2 marine tank vessel i that is controlled, calculated according to paragraph (h)(5) of this section.

EMV2_{iBASE}=Emissions from each Group 2 marine tank vessel i at the baseline date, as calculated in paragraph (h)(5) of this section.

EWV1_{iACTUAL}=Emissions from each Group 1 wastewater stream i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(6) of this section.

EWV1_{iu}=Emissions from each Group 1 wastewater stream i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (h)(6) of this section.

EWV2_{iACTUAL}=Emissions from each Group 2 wastewater stream i that is controlled, calculated according to paragraph (h)(6) of this section.

EWV2_{iBASE}=Emissions from each Group 2 wastewater stream i at the

baseline date, calculated according to paragraph (h)(6) of this section.

n=Number of Group 1 emission points included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

m=Number of Group 2 emission points included in the emissions average. The value of m is not necessarily the same for each kind of emission point.

(i) For an emission point controlled using a reference control technology, the percentage of reduction for calculating credits shall be no greater than the nominal efficiency associated with the reference control technology, unless a higher nominal efficiency is assigned as specified in paragraph (h)(1)(ii) of this section.

(ii) For an emission point controlled to a level more stringent than the reference control technology, the nominal efficiency for calculating credits shall be assigned as described in paragraph (i) of this section. A reference control technology may be approved for use in a different manner and assigned a higher nominal efficiency according to the procedures in paragraph (i) of this section.

(iii) For an emission point controlled using a pollution prevention measure, the nominal efficiency for calculating credits shall be determined as described in paragraph (j) of this section.

(2) Emissions from process vents shall be determined as follows:

(i) Uncontrolled emissions from miscellaneous process vents, EPV1_{iu}, shall be calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(ii) Actual emissions from miscellaneous process vents controlled using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving greater than 98 percent emission reduction, EPV1_{iACTUAL}, shall be calculated according to the following equation:

$$EPV1_{iACTUAL} = EPV1_{iu} \left(1 - \frac{\text{Nominal efficiency}\%}{100\%} \right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 process vents, EPV2_{iACTUAL}:

(A) For a Group 2 process vent controlled by a control device, a recovery device applied as a pollution prevention project, or a pollution

prevention measure, if the control achieves a percentage of reduction less than or equal to a 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu} \times \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

(1) $EPV2_{iu}$ shall be calculated according to the equations and procedures for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section except as provided in paragraph (h)(2)(iii)(A)(3) of this section.

(2) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(2)(iii)(B)(1) through (g)(2)(iii)(B)(3) of this section except as provided in paragraph (h)(2)(iii)(A)(4) of this section.

(3) If a recovery device was added as part of a pollution prevention project, $EPV2_{iu}$ shall be calculated prior to that recovery device. The equation for EPV_{iu} in paragraph (g)(2)(ii) of this section shall be used to calculate $EPV2_{iu}$; however, the sampling site for measurement of vent stream flow rate and organic HAP concentration shall be at the inlet of the recovery device.

(4) If a recovery device was added as part of a pollution prevention project,

the percentage of reduction shall be demonstrated by conducting a performance test at the inlet and outlet of that recovery device.

(B) For a Group 2 process vent controlled using a technology with an approved nominal efficiency greater than a 98 percent or a pollution prevention measure achieving greater than 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu} \left(1 - \frac{\text{Nominal efficiency}\%}{100\%} \right)$$

(iv) Emissions from Group 2 process vents at baseline, $EPV2_{iBASE}$, shall be calculated as follows:

(A) If the process vent was uncontrolled on November 15, 1990, $EPV2_{iBASE} = EPV2_{iu}$, and shall be calculated according to the procedures

and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the process vent was controlled on November 15, 1990,

$$EPV2_{iBASE} = EPV2_{iu} \left(1 - \frac{\text{Percent reduction}\%}{100\%} \right)$$

where $EPV2_{iu}$ is calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section. The percentage of reduction shall be calculated according to the procedures specified in paragraphs (g)(2)(iii)(B)(1) through (g)(2)(iii)(B)(3) of this section.

(C) If a recovery device was added to a process vent as part of a pollution prevention project initiated after November 15, 1990, $EPV2_{iBASE} = EPV2_{iu}$, where $EPV2_{iu}$ is calculated according to paragraph (h)(2)(iii)(A)(3) of this section.

(3) Emissions from storage vessels shall be determined as specified in

§ 63.150(h)(3) of subpart G, except as follows:

(i) All references to § 63.119(b) in § 63.150(h)(3) of subpart G shall be replaced with: § 63.119 (b) or § 63.119(b) except for § 63.119(b)(5) and (b)(6).

(ii) All references to § 63.119(c) in § 63.150(h)(3) of subpart G shall be replaced with: § 63.119(c) or § 63.119(c) except for § 63.119(c)(2).

(iii) All references to § 63.119(d) in § 63.150(h)(3) of subpart G shall be replaced with: § 63.119(d) or § 63.119(d) except for § 63.119(d)(2).

(4) Emissions from gasoline loading racks shall be determined as follows:

(i) Uncontrolled emissions from Group 1 gasoline loading racks,

$EGLR1_{iu}$, shall be calculated according to the procedures and equations for $EGLR_{iu}$ as described in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(ii) Emissions from Group 1 gasoline loading racks if the reference control technology had been applied, $EGLR_{ic}$, shall be calculated according to the procedures and equations in paragraph (g)(4)(v) of this section.

(iii) Actual emissions from Group 1 gasoline loading racks controlled to less than 10 milligrams of TOC per liter of gasoline loaded; $EGLR_{iACTUAL}$, shall be calculated according to the following equation:

$$EGLR1_{iACTUAL} = EGLR1_{iu} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

(iv) The following procedures shall be used to calculate actual emissions from Group 2 gasoline loading racks, $EGLR2_{iACTUAL}$:

(A) For a Group 2 gasoline loading rack controlled by a control device or a pollution prevention measure achieving emissions reduction but where

emissions are greater than the 10 milligrams of TOC per liter of gasoline loaded requirement,

$$EGLR2_{iACTUAL} = EGLR2_{iu} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

(1) $EGLR2_{iu}$ shall be calculated according to the equations and procedures for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.
 (2) The percentage of reduction shall be calculated according to the

procedures in paragraphs (g)(4)(vi)(B)(1) and (g)(4)(vi)(B)(2) of this section.
 (B) For a Group 2 gasoline loading rack controlled by using a technology with an approved nominal efficiency greater than 98 percent or a pollution

prevention measure achieving greater than a 98-percent reduction,

$$EGLR2_{iACTUAL} = EGLR2_{iu} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

(v) Emissions from Group 2 gasoline loading racks at baseline, $EGLR2_{iBASE}$, shall be calculated as follows:

(A) If the gasoline loading rack was uncontrolled on November 15, 1990, $EGLR2_{iBASE} = EGLR2_{iu}$, and shall be calculated according to the procedures

and equations for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.
 (B) If the gasoline loading rack was controlled on November 15, 1990,

$$EGLR2_{iBASE} = EGLR2_{iu} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

where $EGLR2_{iu}$ is calculated according to the procedures and equations for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)(1) and (g)(4)(vi)(B)(2) of this section.

(5) Emissions from marine tank vessels shall be determined as follows:
 (i) Uncontrolled emissions from Group 1 marine tank vessels, $EMV1_{iu}$, shall be calculated according to the procedures and equations for EMV_{iu} as described in paragraph (g)(5)(i) of this section.

(ii) Actual emissions from Group 1 marine tank vessels controlled using a technology or pollution prevention measure with an approved nominal efficiency greater than 97 percent, $EMV_{iACTUAL}$, shall be calculated according to the following equation:

$$EMV1_{iACTUAL} = EMV1_{iu} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

(iii) The following procedures shall be used to calculate actual emissions from

Group 2 marine tank vessels, $EMV2_{iACTUAL}$:

(A) For a Group 2 marine tank vessel controlled by a control device or a

pollution prevention measure achieving a percentage of reduction less than or equal to 97 percent reduction,

$$EMV2_{iACTUAL} = EMV2_{iu} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

(1) $EMV2_{iu}$ shall be calculated according to the equations and procedures for EMV_{iu} in paragraph (g)(5)(i) of this section.

(2) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(1) and (g)(5)(ii)(B)(2) of this section.

(B) For a Group 2 marine tank vessel controlled using a technology or a pollution prevention measure with an approved nominal efficiency greater than 97 percent,

$$EMV2_{iACTUAL} = EMV2_{iu} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

(iv) Emissions from Group 2 marine tank vessels at baseline, $EMV2_{iBASE}$, shall be calculated as follows:

(A) If the marine terminal was uncontrolled on November 15, 1990, $EMV2_{iBASE}$ equals $EMV2_{iu}$, and shall be calculated according to the procedures

and equations for EMV_{iu} in paragraph (g)(5)(i) of this section.
 (B) If the marine tank vessel was controlled on November 15, 1990,

$$EMV2_{iBASE} = EMV2_{iu} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

where $EMV2_{iu}$ is calculated according to the procedures and equations for EMV_{iu} in paragraph (g)(5)(i) of this section.

Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(1) and (g)(5)(ii)(B)(2) of this section.

(6) Emissions from wastewater shall be determined as follows:

(i) For purposes of paragraphs (h)(4)(ii) through (h)(4)(vi) of this section, the following terms will have the meaning given them in paragraphs

(h)(6)(i)(A) through (h)(6)(i)(C) of this section.

(A) *Correctly suppressed* means that a wastewater stream is being managed according to the requirements of §§ 61.343 through 61.347 or § 61.342(c)(1)(iii) of 40 CFR part 61, subpart FF, as applicable, and the emissions from the waste management units subject to those requirements are routed to a control device that reduces HAP emissions by 95 percent or greater.

(B) *Treatment process* has the meaning given in § 61.341 of 40 CFR part 61, subpart FF except that it does not include biological treatment units.

(C) *Vapor control device* means the control device that receives emissions vented from a treatment process or treatment processes.

(ii) The following equation shall be used for each wastewater stream i to calculate EWV_{ic} :

$$EWV_{ic} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s (1 - Fr_m) Fe_m HAP_{im} + (0.05) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s (Fr_m HAP_{im})$$

where:

EWV_{ic} = Monthly wastewater stream emission rate if wastewater stream i were controlled by the reference control technology, megagrams per month.

Q_i = Average flow rate for wastewater stream i , liters per minute.

H_i = Number of hours during the month that wastewater stream i was generated, hours per month.

Fr_m = Fraction removed of organic HAP m in wastewater, from table 7 of this subpart, dimensionless.

Fe_m = Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

s = Total number of organic HAP's in wastewater stream i .

HAP_{im} = Average concentration of organic HAP m in wastewater stream i , parts per million by weight.

(A) HAP_{im} shall be determined from the point of generation or at a location downstream of the point of generation. Wastewater samples shall be collected using the sampling procedures specified in Method 25D of 40 CFR part 60, appendix A. Where feasible, samples shall be taken from an enclosed pipe

prior to the wastewater being exposed to the atmosphere. When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of organic HAP's prior to sampling. The samples collected may be analyzed by either of the following procedures:

(1) A test method or results from a test method that measures organic HAP concentrations in the wastewater, and that has been validated pursuant to section 5.1 or 5.3 of Method 301 of appendix A of this part may be used; or

(2) Method 305 of appendix A of this part may be used to determine C_{im} , the average volatile organic HAP concentration of organic HAP m in wastewater stream i , and then HAP_{im} may be calculated using the following equation: $HAP_{im} = C_{im} / Fr_m$, where Fr_m for organic HAP m is obtained from table 7 of this subpart.

(B) Values for Q_i , HAP_{im} , and C_{im} shall be determined during a performance test conducted under representative conditions. The average value obtained from three test runs shall be used. The values of Q_i , HAP_{im} , and C_{im} shall be

established in the Notification of Compliance Status report and must be updated as provided in paragraph (h)(6)(i)(C) of this section.

(C) If there is a change to the process or operation such that the previously measured values of Q_i , HAP_{im} , and C_{im} are no longer representative, a new performance test shall be conducted to determine new representative values of Q_i , HAP_{im} , and C_{im} . These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following equations shall be used to calculate $EWV_{iACTUAL}$ for each Group 1 wastewater stream i that is correctly suppressed and is treated to a level more stringent than the reference control technology.

(A) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, and the vapor control device achieves a percentage of reduction equal to 95 percent, the following equation shall be used:

$$EWV_{iACTUAL} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [Fc_m HAP_{im} (1 - PR_{im})] + 0.05 (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [HAP_{im} PR_{im}]$$

Where:

$EWV_{iACTUAL}$ = Monthly wastewater stream emission rate if wastewater stream i is treated to a level more

stringent than the reference control technology, megagrams per month.
 PR_{im} = The efficiency of the treatment process, or series of treatment processes, that treat wastewater

stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless, as calculated by:

$$PR_{im} = \frac{HAP_{im-in} - HAP_{im-out}}{HAP_{im-in}}$$

Where:

HAP_{im-in} = Average concentration of organic HAP m, parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater entering the first treatment process in the series.

HAP_{im-out} = Average concentration of organic HAP m, parts per million by

weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater exiting the last treatment process in the series.

All other terms are as defined and determined in paragraph (h)(6)(ii) of this section.

(B) If the Group 1 wastewater stream i is not controlled using a treatment

process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, but the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [Fe_m HAP_{im} (1 - A_m)] + \left(1 - \frac{\text{Nominal efficiency \%}}{100} \right) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [HAP_{im} A_m]$$

Where:

Nominal efficiency = Approved reduction efficiency of the vapor control device, dimensionless, as determined according to the procedures in § 63.652(i).

A_m = The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless.

All other terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(1) If a steam stripper meeting the specifications in the definition of

reference control technology for wastewater is used, A_m shall be equal to the value of Fr_m given in table 7 of this subpart.

(2) If an alternative control device is used, the percentage of reduction must be determined using the equation and methods specified in paragraph (h)(6)(iii)(A) of this section for determining PR_{im} . If the value of PR_{im} is greater than or equal to the value of Fr_m given in table 7 of this subpart, then A_m equals Fr_m unless a higher nominal efficiency has been approved. If a higher nominal efficiency has been approved for the treatment process, the owner or operator shall determine $EWW1_{iACTUAL}$ according to paragraph (h)(6)(iii)(B) of

this section rather than paragraph (h)(6)(iii)(A) of this section. If PR_{im} is less than the value of Fr_m given in table 7 of this subpart, emissions averaging shall not be used for this emission point.

(C) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated hazardous air pollutant that is greater than that specified in table 7 of this subpart, and the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [Fe_m HAP_{im} (1 - PR_{im})] + \left(1 - \frac{\text{Nominal efficiency \%}}{100} \right) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [HAP_{im} PR_{im}]$$

where all terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(iv) The following equation shall be used to calculate $EWW2_{iBASE}$ for each Group 2 wastewater stream i that on

November 15, 1990 was not correctly suppressed or was correctly suppressed but not treated:

$$EWW2_{iBASE} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s Fe_m HAP_{im}$$

Where:

$EWW2_{iBASE}$ = Monthly wastewater stream emission rate if wastewater stream i is not correctly suppressed, megagrams per month.

Q_i , H_i , s , Fe_m , and HAP_{im} are as defined and determined according to paragraphs

(h)(6)(ii) and (h)(6)(iii)(A) of this section.

(v) The following equation shall be used to calculate $EWW2_{iBASE}$ for each Group 2 wastewater stream i on November 15, 1990 was correctly suppressed. $EWW2_{iBASE}$ shall be calculated as if the control methods

being used on November 15, 1990 are in place and any control methods applied after November 15, 1990 are ignored. However, values for the parameters in the equation shall be representative of present production levels and stream properties.

$$EWW2_{BASE} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [Fe_m HAP_{im} (1 - PR_{im})] + \left(1 - \frac{R_i}{100\%}\right) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [HAP_{im} PR_{im}]$$

where R_i is calculated according to paragraph (h)(6)(vii) of this section and all other terms are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(vi) For Group 2 wastewater streams that are correctly suppressed, $EWW2_{ACTUAL}$ shall be calculated according to the equation for $EWW2_{BASE}$ in paragraph (h)(6)(v) of this section. $EWW2_{ACTUAL}$ shall be calculated with all control methods in place accounted for.

(vii) The reduction efficiency, R_i , of the vapor control device shall be

demonstrated according to the following procedures:

(A) Sampling sites shall be selected using Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate.

(B) The mass flow rate of organic compounds entering and exiting the control device shall be determined as follows:

(1) The time period for the test shall not be less than 3 hours during which at least three runs are conducted.

(2) A run shall consist of a 1-hour period during the test. For each run:

(i) The volume exhausted shall be determined using Methods 2, 2A, 2C, or

2D of 40 CFR part 60 appendix A, as appropriate;

(ii) The organic concentration in the vent stream entering and exiting the control device shall be determined using Method 18 of 40 CFR part 60, appendix A. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A of this part may be used.

(3) The mass flow rate of organic compounds entering and exiting the control device during each run shall be calculated as follows:

$$E_a = \frac{0.0416}{10^6 \times m} \left[\sum_{p=1}^m V_{ap} \left(\sum_{i=1}^n C_{aip} MW_i \right) \right]$$

$$E_b = \frac{0.0416}{10^6 \times m} \left[\sum_{p=1}^m V_{bp} \left(\sum_{i=1}^n C_{bip} MW_i \right) \right]$$

Where:

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

V_{ap} = Average volumetric flow rate of vent stream exiting the control device during run p at standard conditions, cubic meters per hour.

V_{bp} = Average volumetric flow rate of vent stream entering the control device during run p at standard conditions, cubic meters per hour.

p = Run.

m = Number of runs.

C_{aip} = Concentration of organic compound i measured in the vent stream exiting the control device during run p as determined by Method 18 of 40 CFR part 60 appendix A, parts per million by volume on a dry basis.

C_{bip} = Concentration of organic compound i measured in the vent stream entering the control device during run p as determined by Method 18 of 40 CFR part 60, appendix A, parts per million by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, kilograms per kilogram-mole.

n = Number of organic compounds in the vent stream.

0.0416 = Conversion factor for molar volume, kilograms-mole per cubic meter at 293 kelvin and 760 millimeters mercury absolute.

(C) The organic reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Total organic reduction efficiency for the control device, percentage.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

(i) The following procedures shall be followed to establish nominal efficiencies. The procedures in paragraphs (i)(1) through (i)(6) of this section shall be followed for control technologies that are different in use or design from the reference control technologies and achieve greater percentages of reduction than the percentages of efficiency assigned to the reference control technologies in § 63.641.

(1) In those cases where the owner or operator is seeking permission to take credit for use of a control technology

that is different in use or design from the reference control technology, and the different control technology will be used in more than three applications at a single plant site, the owner or operator shall submit the information specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section to the Administrator in writing:

(i) Emission stream characteristics of each emission point to which the control technology is or will be applied including the kind of emission point, flow, organic HAP concentration, and all other stream characteristics necessary to design the control technology or determine its performance;

(ii) Description of the control technology including design specifications;

(iii) Documentation demonstrating to the Administrator's satisfaction the control efficiency of the control technology. This may include performance test data collected using an appropriate EPA method or any other method validated according to Method 301 of appendix A of this part. If it is infeasible to obtain test data, documentation may include a design evaluation and calculations. The engineering basis of the calculation procedures and all inputs and

assumptions made in the calculations shall be documented; and

(iv) A description of the parameter or parameters to be monitored to ensure that the control technology will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) The Administrator shall determine within 120 calendar days whether an application presents sufficient information to determine nominal efficiency. The Administrator reserves the right to request specific data in addition to the items listed in paragraph (i)(1) of this section.

(3) The Administrator shall determine within 120 calendar days of the submittal of sufficient data whether a control technology shall have a nominal efficiency and the level of that nominal efficiency. If, in the Administrator's judgment, the control technology achieves a level of emission reduction greater than the reference control technology for a particular kind of emission point, the Administrator will publish a **Federal Register** notice establishing a nominal efficiency for the control technology.

(4) The Administrator may grant conditional permission to take emission credits for use of the control technology on requirements that may be necessary to ensure operation and maintenance to achieve the specified nominal efficiency.

(5) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology and the different control technology will be used in no more than three applications at a single plant site, the information

listed in paragraphs (i)(1)(i) through (i)(1)(iv) of this section can be submitted to the permitting authority for the source for approval instead of the Administrator.

(i) In these instances, use and conditions for use of the control technology can be approved by the permitting authority. The permitting authority shall follow the procedures specified in paragraphs (i)(2) through (i)(4) of this section except that, in these instances, a **Federal Register** notice is not required to establish the nominal efficiency for the different technology.

(ii) If, in reviewing the submittal, the permitting authority believes the control technology has broad applicability for use by other sources, the permitting authority shall submit the information provided in the application to the Director of the EPA Office of Air Quality Planning and Standards. The Administrator shall review the technology for broad applicability and may publish a **Federal Register** notice; however, this review shall not affect the permitting authority's approval of the nominal efficiency of the control technology for the specific application.

(6) If, in reviewing an application for a control technology for an emission point, the Administrator or permitting authority determines the control technology is not different in use or design from the reference control technology, the Administrator or permitting authority shall deny the application.

(j) The following procedures shall be used for calculating the efficiency (percentage of reduction) of pollution prevention measures:

(1) A pollution prevention measure is any practice that meets the criteria of

paragraphs (j)(1)(i) and (j)(1)(ii) of this section.

(i) A pollution prevention measure is any practice that results in a lesser quantity of organic HAP emissions per unit of product released to the atmosphere prior to out-of-process recycling, treatment, or control of emissions while the same product is produced.

(ii) Pollution prevention measures may include: Substitution of feedstocks that reduce HAP emissions, alterations to the production process to reduce the volume of materials released to the environment, equipment modifications; housekeeping measures, and in-process recycling that returns waste materials directly to production as raw materials. Production cutbacks do not qualify as pollution prevention.

(2) The emission reduction efficiency of pollution prevention measures implemented after November 15, 1990 can be used in calculating the actual emissions from an emission point in the debit and credit equations in paragraphs (g) and (h) of this section.

(i) For pollution prevention measures, the percentage of reduction used in the equations in paragraphs (g)(2) and (g)(3) of this section and paragraphs (h)(2) through (h)(4) of this section is the difference in percentage between the monthly organic HAP emissions for each emission point after the pollution prevention measure for the most recent month versus monthly emissions from the same emission point before the pollution prevention measure, adjusted by the volume of product produced during the two monthly periods.

(ii) The following equation shall be used to calculate the percentage of reduction of a pollution prevention measure for each emission point.

$$\text{Percent reduction} = \frac{E_B \frac{(E_{pp} \times P_B)}{P_{pp}}}{E_B} \times 100\%$$

Where:

Percent reduction=Efficiency of pollution prevention measure (percentage of organic HAP reduction).

E_B =Monthly emissions before the pollution prevention measure, megagrams per month, determined as specified in paragraphs (j)(2)(ii)(A), (j)(2)(ii)(B), and (j)(2)(ii)(C) of this section.

E_{pp} =Monthly emissions after the pollution prevention measure,

megagrams per month, as determined for the most recent month, determined as specified in paragraphs (j)(2)(ii)(D) or (j)(2)(ii)(E) of this section.

P_B =Monthly production before the pollution prevention measure, megagrams per month, during the same period over which E_B is calculated.

P_{pp} =Monthly production after the pollution prevention measure, megagrams per month, as

determined for the most recent month.

(A) The monthly emissions before the pollution prevention measure, E_B , shall be determined in a manner consistent with the equations and procedures in paragraphs (g)(2), (g)(3), (g)(4), and (g)(5) of this section for miscellaneous process vents, storage vessels, gasoline loading racks, and marine tank vessels.

(B) For wastewater, E_B shall be calculated as follows:

$$E_B = \sum_{i=1}^n \left[\left(6.0 \times 10^{-8} \right) Q_{Bi} H_{Bi} \sum_{m=1}^s Fe_m HAP_{Bim} \right]$$

where:

n=Number of wastewater streams.

Q_{Bi} =Average flow rate for wastewater stream i before the pollution prevention measure, liters per minute.

H_{Bi} =Number of hours per month that wastewater stream i was discharged before the pollution prevention measure, hours per month.

s=Total number of organic HAP's in wastewater stream i.

Fe_m =Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

HAP_{Bim} =Average concentration of organic HAP m in wastewater stream i, defined and determined according to paragraph (h)(6)(ii)(A)(2) of this section, before the pollution prevention measure, parts per million by weight, as measured before the implementation of the pollution measure.

(C) If the pollution prevention measure was implemented prior to July 14, 1994, records may be used to determine E_B .

(D) The monthly emissions after the pollution prevention measure, E_{pp} , may be determined during a performance test or by a design evaluation and documented engineering calculations. Once an emissions-to-production ratio has been established, the ratio can be used to estimate monthly emissions from monthly production records.

(E) For wastewater, E_{pp} shall be calculated using the following equation:

$$E_{pp} = \sum_{i=1}^n \left[\left(6.0 \times 10^{-8} \right) Q_{ppi} H_{ppi} \sum_{m=1}^s Fe_m HAP_{ppim} \right]$$

where n, Q, H, s, Fe_m , and HAP are defined and determined as described in paragraph (j)(2)(ii)(B) of this section except that Q_{ppi} , H_{ppi} , and HAP_{ppim} shall be determined after the pollution prevention measure has been implemented.

(iii) All equations, calculations, test procedures, test results, and other information used to determine the percentage of reduction achieved by a pollution prevention measure for each emission point shall be fully documented.

(iv) The same pollution prevention measure may reduce emissions from multiple emission points. In such cases, the percentage of reduction in emissions for each emission point must be calculated.

(v) For the purposes of the equations in paragraphs (h)(2) through (h)(6) of this section used to calculate credits for emission points controlled more stringently than the reference control technology, the nominal efficiency of a pollution prevention measure is equivalent to the percentage of reduction of the pollution prevention measure. When a pollution prevention measure is used, the owner or operator of a source is not required to apply to the Administrator for a nominal efficiency and is not subject to paragraph (i) of this section.

(k) The owner or operator shall demonstrate that the emissions from the emission points proposed to be included in the average will not result in greater hazard or, at the option of the State or local permitting authority,

greater risk to human health or the environment than if the emission points were controlled according to the provisions in §§ 63.643 through 63.647, and §§ 63.650 and 63.651.

(1) This demonstration of hazard or risk equivalency shall be made to the satisfaction of the State or local permitting authority.

(i) The State or local permitting authority may require owners and operators to use specific methodologies and procedures for making a hazard or risk determination.

(ii) The demonstration and approval of hazard or risk equivalency may be made according to any guidance that the EPA makes available for use.

(2) Owners and operators shall provide documentation demonstrating the hazard or risk equivalency of their proposed emissions average in their Implementation Plan.

(3) An emissions averaging plan that does not demonstrate an equivalent or lower hazard or risk to the satisfaction of the State or local permitting authority shall not be approved. The State or local permitting authority may require such adjustments to the emissions averaging plan as are necessary in order to ensure that the average will not result in greater hazard or risk to human health or the environment than would result if the emission points were controlled according to §§ 63.643 through 63.647, and §§ 63.650 and 63.651.

(4) A hazard or risk equivalency demonstration shall:

(i) Be a quantitative, bona fide chemical hazard or risk assessment;

(ii) Account for differences in chemical hazard or risk to human health or the environment; and

(iii) Meet any requirements set by the State or local permitting authority for such demonstrations.

(l) For periods of excess emissions, an owner or operator may request that the provisions of paragraphs (l)(1) through (l)(4) of this section be followed instead of the procedures in paragraphs (f)(3)(i) and (f)(3)(ii) of this section.

(1) The owner or operator shall notify the Administrator of excess emissions in the Periodic Reports as required in § 63.654(g)(6).

(2) The owner or operator shall demonstrate that other types of monitoring data or engineering calculations are appropriate to establish that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits. This demonstration shall be made to the Administrator's satisfaction, and the Administrator may establish procedures for demonstrating compliance that are acceptable.

(3) The owner or operator shall provide documentation of the period of excess emissions and the other type of monitoring data or engineering calculations to be used to demonstrate that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits.

(4) The Administrator may assign full or partial credit and debits upon review of the information provided.

§ 63.653 Monitoring, recordkeeping, and implementation plan for emission averaging.

(a) For each emission point included in an emissions average, the owner or operator shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with §§ 63.643 through 63.647, and §§ 63.650 and 63.651. The specific requirements for miscellaneous process vents, storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in paragraphs (a)(1) through (a)(7) of this section.

(1) The source shall implement the following testing, monitoring, recordkeeping, and reporting procedures for each miscellaneous process vent equipped with a flare, incinerator, boiler, or process heater:

(i) Conduct initial performance tests to determine the percentage of reduction as specified in § 63.645 of this subpart and § 63.116 of subpart G; and

(ii) Monitor the operating parameters specified in § 63.644, as appropriate for the specific control device.

(2) The source shall implement the following procedures for each miscellaneous process vent, equipped with a carbon adsorber, absorber, or condenser but not equipped with a control device:

(i) Determine the flow rate and organic HAP concentration using the methods specified in § 63.115 (a)(1) and (a)(2), § 63.115 (b)(1) and (b)(2), and § 63.115(c)(3) of subpart G; and

(ii) Monitor the operating parameters specified in § 63.114 of subpart G, as appropriate for the specific recovery device.

(3) The source shall implement the following procedures for each storage vessel controlled with an internal floating roof, external roof, or a closed vent system with a control device, as appropriate to the control technique:

(i) Perform the monitoring or inspection procedures in § 63.646 of this subpart and § 63.120 of subpart G; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in § 63.646 of this subpart and § 63.120(d) of subpart G.

(4) For each gasoline loading rack that is controlled, perform the testing and monitoring procedures specified in §§ 63.425 and 63.427 of subpart R of this part.

(5) For each marine tank vessel that is controlled, perform the compliance, monitoring, and performance testing, procedures specified in §§ 63.563, 63.564, and 63.565 of subpart Y of this part.

(6) The source shall implement the following procedures for wastewater emission points, as appropriate to the control techniques:

(i) For wastewater treatment processes, conduct tests as specified in § 61.355 of subpart FF of part 60;

(ii) Conduct inspections and monitoring as specified in §§ 61.343 through 61.349 and § 61.354 of 40 CFR part 61, subpart FF.

(7) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in §§ 63.643 through 63.647 and §§ 63.650 and 63.651, the owner or operator shall establish a site-specific monitoring parameter and shall submit the information specified in § 63.654(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by § 63.654 shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by § 63.654.

(d) Each owner or operator of an existing source who elects to comply with § 63.654 (g) and (h) by using emissions averaging for any emission points shall submit an Implementation Plan.

(1) The Implementation Plan shall be submitted no later than 18 months prior to the compliance date in § 63.640(h). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If an owner or operator submits the information specified in paragraph (d)(2) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating the previously submitted information.

(2) The Implementation Plan shall include the information specified in paragraphs (d)(2)(i) through (d)(2)(ix) of this section for all points included in the average.

(i) The identification of all emission points in the planned emissions average and notation of whether each emission point is a Group 1 or Group 2 emission point as defined in § 63.641.

(ii) The projected annual emission debits and credits for each emission point and the sum for the emission points involved in the average calculated according to § 63.652. The annual projected credits must be greater

than the projected debits, as required under § 63.652(e)(3).

(iii) The specific control technology or pollution prevention measure that will be used for each emission point included in the average and date of application or expected date of application.

(iv) The specific identification of each emission point affected by a pollution prevention measure. To be considered a pollution prevention measure, the criteria in § 63.652(j)(1) must be met. If the same pollution prevention measure reduces or eliminates emissions from multiple emission points in the average, the owner or operator must identify each of these emission points.

(v) A statement that the compliance demonstration, monitoring, inspection, recordkeeping, and reporting provisions in paragraphs (a), (b), and (c) of this section that are applicable to each emission point in the emissions average will be implemented beginning on the date of compliance.

(vi) Documentation of the information listed in paragraphs (d)(2)(vi)(A) through (d)(2)(vi)(D) of this section for each emission point included in the average.

(A) The values of the parameters used to determine whether each emission point in the emissions average is Group 1 or Group 2.

(B) The estimated values of all parameters needed for input to the emission debit and credit calculations in § 63.652 (g) and (h). These parameter values or, as appropriate, limited ranges for the parameter values, shall be specified in the source's Implementation Plan as enforceable operating conditions. Changes to these parameters must be reported in the next Periodic Report.

(C) The estimated percentage of reduction if a control technology achieving a lower percentage of reduction than the efficiency of the reference control technology, as defined in § 63.641, is or will be applied to the emission point.

(D) The anticipated nominal efficiency if a control technology achieving a greater percentage emission reduction than the efficiency of the reference control technology is or will be applied to the emission point. The procedures in § 63.652(i) shall be followed to apply for a nominal efficiency.

(vii) The information specified in § 63.654(h)(4) for:

(A) Each miscellaneous process vent controlled by a pollution prevention measure or control technique for which monitoring parameters or inspection procedures are not specified in

paragraphs (a)(1) or (a)(2) of this section; and

(B) Each storage vessel controlled by a pollution prevention measure or a control technique other than an internal or external floating roof or a closed vent system with a control device.

(viii) Documentation of the information listed in paragraphs (d)(2)(viii)(A) through (d)(2)(viii)(G) of this section for each process wastewater stream included in the average.

(A) The information used to determine whether the wastewater stream is a Group 1 or Group 2 wastewater stream.

(B) The estimated values of all parameters needed for input to the wastewater emission credit and debit calculations in § 63.652(h)(6).

(C) The estimated percentage of reduction if the wastewater stream is or will be controlled using a treatment process or series of treatment processes that achieves an emission reduction less than or equal to the emission reduction specified in table 7 of this subpart.

(D) The estimated percentage of reduction if a control technology achieving less than or equal to 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(E) The estimated percentage of reduction if a pollution prevention measure is or will be applied.

(F) The anticipated nominal efficiency if the owner or operator plans to apply for a nominal efficiency under § 63.652(i). A nominal efficiency shall be applied for if:

(1) A control technology is or will be applied to the wastewater stream and achieves an emission reduction greater than the emission reduction specified in table 7 of this subpart; or

(2) A control technology achieving greater than 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(G) For each pollution prevention measure, treatment process, or control device used to reduce air emissions of organic HAP's from wastewater and for which no monitoring parameters or inspection procedures are specified in § 63.647, the information specified in § 63.654(h)(4) shall be included in the Implementation Plan.

(ix) Documentation required in § 63.652(k) demonstrating the hazard or risk equivalency of the proposed emissions average.

(3) The Administrator shall determine within 120 calendar days whether the Implementation Plan submitted presents sufficient information. The

Administrator shall either approve the Implementation Plan, request changes, or request that the owner or operator submit additional information. Once the Administrator receives sufficient information, the Administrator shall approve, disapprove, or request changes to the plan within 120 calendar days.

§ 63.654 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to the wastewater provisions in § 63.647 shall comply with the recordkeeping and reporting provisions in §§ 61.356 and 61.357 of 40 CFR part 61 subpart FF. There are no additional reporting and recordkeeping requirements for wastewater under this subpart unless a wastewater stream is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in § 63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(b) Each owner or operator subject to the gasoline loading rack provisions in § 63.650 shall comply with the recordkeeping and reporting provisions in § 63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of subpart R of this part. These requirements are summarized in table 4 of this subpart. There are no additional reporting and recordkeeping requirements for gasoline loading racks under this subpart unless a loading rack is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in § 63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(c) Each owner or operator subject to the marine tank vessel loading operation standards in § 63.651 shall comply with the recordkeeping and reporting provisions in §§ 63.566 and 63.567(a) and § 63.567 (c) through (i) of subpart Y of this part. These requirements are summarized in table 5 of this subpart. There are no additional reporting and recordkeeping requirements for marine tank vessel loading operations under this subpart unless marine tank vessel loading operations are included in an emissions average. Recordkeeping and reporting for emissions averages are specified in § 63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(d) Each owner or operator subject to the equipment leaks standards in § 63.648 shall comply with the recordkeeping and reporting provisions in paragraphs (d)(1) through (d)(3) of this section.

(1) Sections 60.486 and 60.487 of subpart VV of part 60, or §§ 63.181 and 63.182 of subpart H of this part except for § 63.182, paragraphs (b), (c)(2), and (c)(4).

(2) The Notification of Compliance Status report required by § 63.182(c) of subpart H and the initial semiannual report required by § 60.487(b) of 40 CFR part 60, subpart VV shall be submitted within 150 days of the compliance date specified in § 63.640(h); the requirements of subpart H of this part are summarized in table 3 of this subpart.

(3) An owner or operator who determines that a compressor qualifies for the hydrogen service exemption in § 63.646 shall also keep a record of the demonstration required by § 63.646.

(e) Each owner or operator of a source subject to this subpart shall submit the reports listed in paragraphs (e)(1) through (e)(3) of this section except as provided in paragraph (h)(5) of this section, and shall keep records as described in paragraph (i) of this section.

(1) A Notification of Compliance Status report as described in paragraph (f) of this section;

(2) Periodic Reports as described in paragraph (g) of this section; and

(3) Other reports as described in paragraph (h) of this section.

(f) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in § 63.640(h). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in § 63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in § 63.640(h). If an owner or operator submits the information specified in paragraphs (f)(1) through (f)(5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(1) The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1)(i) through (f)(1)(v) of this section.

(i) For storage vessels, this report shall include the information specified in paragraphs (f)(1)(i)(A) through (f)(1)(i)(D) of this section.

(A) Identification of each storage vessel subject to this subpart, whether the vessel is Group 1 or Group 2, and the method of compliance for each Group 1 storage vessel that is not included in an emissions average (i.e.,

internal floating roof, external floating roof, or closed-vent system and control device).

(B) If a closed vent system and a control device other than a flare is used to comply with § 63.646 the owner or operator shall submit:

(1) A description of the parameter or parameters to be monitored to ensure that the control device is being properly operated and maintained, an explanation of the criteria used for selection of that parameter (or parameters), and the frequency with which monitoring will be performed; and either

(2) The design evaluation documentation specified in § 63.120(d)(1)(i) of subpart G, if the owner or operator elects to prepare a design evaluation; or

(3) If the owner or operator elects to submit the results of a performance test, identification of the storage vessel and control device for which the performance test will be submitted, and identification of the emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted.

(C) If a closed vent system and control device other than a flare is used, the owner or operator shall submit:

(1) The operating range for each monitoring parameter. The specified operating range shall represent the conditions for which the control device is being properly operated and maintained.

(2) If a performance test is conducted instead of a design evaluation, results of the performance test demonstrating that the control device achieves greater than or equal to the required control efficiency. A performance test conducted prior to the compliance date of this subpart can be used to comply with this requirement, provided that the test was conducted using EPA methods and that the test conditions are representative of current operating practices.

(D) If a closed vent system and a flare is used, the owner or operator shall submit:

(1) Flare design (e.g., steam-assisted, air-assisted, or nonassisted);

(2) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by § 63.120(e) of subpart G of this part; and

(3) All periods during the compliance determination when the pilot flame is absent.

(ii) For miscellaneous process vents, identification of each miscellaneous process vent subject to this subpart,

whether the process vent is Group 1 or Group 2, and the method of compliance for each Group 1 miscellaneous process vent that is not included in an emissions average (e.g., use of a flare or other control device meeting the requirements of § 63.643(a)).

(iii) For miscellaneous process vents controlled by control devices required to be tested under § 63.645 of this subpart and § 63.116(c) of subpart G of this part, performance test results including the information in paragraphs (f)(1)(iii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.645 and that the test conditions are representative of current operating conditions.

(A) The percentage of reduction of organic HAP's or TOC, or the outlet concentration of organic HAP's or TOC (parts per million by volume on a dry basis corrected to 3 percent oxygen), determined as specified in § 63.116(c) of subpart G of this part; and

(B) The value of the monitored parameters specified in table 10 of this subpart, or a site-specific parameter approved by the permitting authority, averaged over the full period of the performance test.

(iv) For miscellaneous process vents controlled by flares, performance test results including the information in paragraphs (f)(1)(iv)(A) and (B) of this section;

(A) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by § 63.645 of this subpart and § 63.116(a) of subpart G of this part, and

(B) A statement of whether a flame was present at the pilot light over the full period of the compliance determination.

(v) For equipment leaks complying with § 63.648(c) (i.e., complying with the requirements of subpart H of this part), the Notification of Compliance Report Status report information required by § 63.182(c) of subpart H and whether the percentage of leaking valves will be reported on a process unit basis or a sourcewide basis.

(2) If initial performance tests are required by §§ 63.643 through 63.653 of this subpart, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source.

(i) For additional tests performed using the same method, the results specified in paragraph (f)(1) of this

section shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(iii) Performance tests are required only if specified by §§ 63.643 through 63.653 of this subpart. Initial performance tests are required for some kinds of emission points and controls. Periodic testing of the same emission point is not required.

(3) For each monitored parameter for which a range is required to be established under § 63.120(d) of subpart G of this part for storage vessels or § 63.644 for miscellaneous process vents, the Notification of Compliance Status report shall include the information in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

(i) The specific range of the monitored parameter(s) for each emission point;

(ii) The rationale for the specific range for each parameter for each emission point, including any data and calculations used to develop the range and a description of why the range ensures compliance with the emission standard.

(A) If a performance test is required by this subpart for a control device, the range shall be based on the parameter values measured during the performance test supplemented by engineering assessments and manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of permitted parameter values.

(B) If a performance test is not required by this subpart for a control device, the range may be based solely on engineering assessments and manufacturers' recommendations.

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(4) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report.

(5) For emission points included in an emissions average, the Notification of Compliance Status report shall include

the values of the parameters needed for input to the emission credit and debit equations in § 63.652(g) and (h), calculated or measured according to the procedures in § 63.652(g) and (h), and the resulting credits and debits for the first quarter of the year. The first quarter begins on the compliance date specified in § 63.640.

(g) The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occur. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emissions averages, as provided in paragraph (g)(8) of this section. An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph if the reports contain the information required by paragraphs (g)(1) through (g)(8) of this section.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraph (g)(2) through (g)(5) of this section except that information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source.

(2) An owner or operator who elects to comply with § 63.646 by using a fixed roof and an internal floating roof or by using an external floating roof converted to an internal floating roof shall submit the results of each inspection conducted in accordance with § 63.120(a) of subpart G of this part in which a failure is detected in the control equipment.

(i) For vessels for which annual inspections are required under § 63.120(a)(2)(i) or (a)(3)(ii) of subpart G of this part, the specifications and requirements listed in paragraphs (g)(2)(i)(A) through (g)(2)(i)(C) of this section apply.

(A) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or

there are visible gaps between the seal and the wall of the storage vessel.

(B) Except as provided in paragraph (g)(2)(i)(C) of this section, each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(C) If an extension is utilized in accordance with § 63.120(a)(4) of subpart G of this part, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in § 63.120(a)(4) of subpart G of this part; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(ii) For vessels for which inspections are required under § 63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G of this part (i.e., internal inspections), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) and (g)(2)(ii)(B) of this section apply.

(A) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(3) An owner or operator who elects to comply with § 63.646 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(i) through (g)(3)(iii) of this section.

(i) The owner or operator shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with § 63.120(b) of subpart G of this part in which the seal and seal gap requirements of § 63.120(b)(3), (b)(4), (b)(5), or (b)(6) of subpart G of this part are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A) through (g)(3)(i)(D) of this section.

(A) The date of the seal gap measurement.

(B) The raw data obtained in the seal gap measurement and the calculations described in § 63.120(b)(3) and (b)(4) of subpart G of this part.

(C) A description of any seal condition specified in § 63.120(b)(5) or (b)(6) of subpart G of this part that is not met.

(D) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(ii) If an extension is utilized in accordance with § 63.120(b)(7)(ii) or (b)(8) of subpart G of this part, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in § 63.120(b)(7)(ii) or (b)(8) of subpart G of this part, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(iii) The owner or operator shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by § 63.120(b)(10) of subpart G of this part. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(iii)(A) and (g)(3)(iii)(B) of this section.

(A) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than 10 percent open area.

(B) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(4) An owner or operator who elects to comply with § 63.646 by using an external floating roof converted to an internal floating roof shall comply with the periodic reporting requirements of paragraph (g)(2) of this section.

(5) An owner or operator who elects to comply with § 63.646 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in paragraphs (g)(5)(i) through (g)(5)(iii) of this section.

(i) The Periodic Report shall include the information specified in paragraphs (g)(5)(i)(A) and (g)(5)(i)(B) of this section for those planned routine maintenance

operations that would require the control device not to meet the requirements of § 63.119(e)(1) or (e)(2) of subpart G of this part, as applicable.

(A) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description shall include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(B) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description shall include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the requirements of § 63.119 (e)(1) or (e)(2) of subpart G of this part, as applicable, due to planned routine maintenance.

(ii) If a control device other than a flare is used, the Periodic Report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance Status report. The description shall include: Identification of the control device for which the measured parameters were outside of the established ranges, and causes for the measured parameters to be outside of the established ranges.

(iii) If a flare is used, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in § 63.11(b) of subpart A of this part and shall include: Identification of the flare that does not meet the general requirements specified in § 63.11(b) of subpart A of this part, and reasons the flare did not meet the general requirements specified in § 63.11(b) of subpart A of this part.

(6) For miscellaneous process vents for which continuous parameter monitors are required by this subpart, periods of excess emissions shall be identified in the Periodic Reports and shall be used to determine compliance with the emission standards.

(i) Period of excess emission means any of the following conditions:

(A) An operating day when the daily average value of a monitored parameter, except presence of a flare pilot flame, is outside the range specified in the Notification of Compliance Status report. Monitoring data recorded during periods of monitoring system breakdown, repairs, calibration checks and zero (low-level) and high-level adjustments shall not be used in computing daily average values of monitored parameters.

(B) An operating day when all pilot flames of a flare are absent.

(C) An operating day when monitoring data required to be recorded in paragraphs (i)(3) (i) and (ii) of this section are available for less than 75 percent of the operating hours.

(D) For data compression systems approved under paragraph (h)(5)(iii) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

(ii) For miscellaneous process vents, excess emissions shall be reported for the operating parameters specified in table 10 of this subpart unless other site-specific parameter(s) have been approved by the operating permit authority.

(iii) Periods of startup, shutdown, and malfunction that meet the definitions in § 63.2 of subpart A of this part and periods of performance testing and monitoring system calibration shall not be considered periods of excess emissions. Malfunctions may include process unit, control device, or monitoring system malfunctions.

(7) If a performance test for determination of compliance for a new emission point subject to this subpart or for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic Report, the results of the performance test shall be included in the Periodic Report.

(i) Results of the performance test shall include the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) and the values of the monitored operating parameters.

(ii) The complete test report shall be maintained onsite.

(8) The owner or operator of a source shall submit quarterly reports for all emission points included in an emissions average.

(i) The quarterly reports shall be submitted no later than 60 calendar days after the end of each quarter. The first report shall be submitted with the Notification of Compliance Status report no later than 150 days after the compliance date specified in § 63.640.

(ii) The quarterly reports shall include:

(A) The information specified in this paragraph and in paragraphs (g)(2) through (g)(7) of this section for all storage vessels and miscellaneous process vents included in an emissions average;

(B) The information required to be reported by § 63.428(h)(1) of subpart R

of this part for each gasoline loading rack included in an emissions average, unless this information has already been submitted in a separate report;

(C) The information required to be included in quarterly reports by §§ 63.567(f) and 63.567(i)(2) of subpart Y of this part for each marine tank vessel loading operation included in an emissions average, unless the information has already been submitted in a separate report;

(D) Any information pertaining to each wastewater stream included in an emissions average that the source is required to report under the Implementation Plan for the source;

(E) The credits and debits calculated each month during the quarter;

(F) A demonstration that debits calculated for the quarter are not more than 1.30 times the credits calculated for the quarter, as required under § 63.652(e)(4);

(G) The values of any inputs to the credit and debit equations in § 63.652 (g) and (h) that change from month to month during the quarter or that have changed since the previous quarter; and

(H) Any other information the source is required to report under the Implementation Plan for the source.

(iii) Every fourth quarterly report shall include the following:

(A) A demonstration that annual credits are greater than or equal to annual debits as required by § 63.652(e)(3); and

(B) A certification of compliance with all the emissions averaging provisions in § 63.652 of this subpart.

(h) Other reports shall be submitted as specified in subpart A of this part and as follows:

(1) Reports of startup, shutdown, and malfunction required by § 63.10(d)(5) of subpart A of this part; and

(2) For storage vessels, notifications of inspections as specified in paragraphs (h)(2)(i) and (h)(2)(ii) of this section;

(i) In order to afford the Administrator the opportunity to have an observer present, the owner or operator shall notify the Administrator of the refilling of each Group 1 storage vessel that has been emptied and degassed.

(A) Except as provided in paragraphs (h)(2)(i) (B) and (C) of this section, the owner or operator shall notify the Administrator in writing at least 30 calendar days prior to filling or refilling of each storage vessel with organic HAP's to afford the Administrator the opportunity to inspect the storage vessel prior to refilling.

(B) Except as provided in paragraph (h)(2)(i)(C) of this section, if the internal inspection required by §§ 63.120(a)(2), 63.120(a)(3), or 63.120(b)(10) of subpart

G of this part is not planned and the owner or operator could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP's, the owner or operator shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. This notification, including the written documentation, may also be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

(C) The State or local permitting authority can waive the notification requirements of paragraphs (h)(2)(i)(A) and/or (h)(2)(i)(B) of this section for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notification required by paragraph (h)(2)(i)(A) of this section, or sooner than 7 days after submitting the notification required by paragraph (h)(2)(i)(B) of this section for all storage vessels, or for individual storage vessels on a case-by-case basis.

(ii) In order to afford the Administrator the opportunity to have an observer present, the owner or operator of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by § 63.120 (b)(1) or (b)(2) of subpart G of this part. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

(3) For owners or operators of sources required to request approval for a nominal control efficiency for use in calculating credits for an emissions average, the information specified in § 63.652(h).

(4) The owner or operator who requests approval to monitor a different parameter than those listed in § 63.644 for miscellaneous process vents or who is required by § 63.653(a)(8) to establish a site-specific monitoring parameter for a point in an emissions average shall submit the information specified in paragraphs (h)(4)(i) through (h)(4)(iii) of this section. For new or reconstructed sources, the information shall be submitted with the application for approval of construction or reconstruction required by § 63.5(d) of subpart A and for existing sources, and

the information shall be submitted no later than 18 months prior to the compliance date. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) A description of the parameter(s) to be monitored to determine whether excess emissions occur and an explanation of the criteria used to select the parameter(s).

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine excess emissions and the schedule for this demonstration. The owner or operator must certify that they will establish a range for the monitored parameter as part of the Notification of Compliance Status report required in paragraphs (e) and (f) of this section.

(iii) The frequency and content of monitoring, recording, and reporting if: monitoring and recording are not continuous; or if periods of excess emissions, as defined in paragraph (g)(6) of this section, will not be identified in Periodic Reports required under paragraphs (e) and (g) of this section. The rationale for the proposed monitoring, recording, and reporting system shall be included.

(5) An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in paragraph (i) of this section.

(i) Requests shall be submitted with the Application for Approval of Construction or Reconstruction for new sources and no later than 18 months prior to the compliance date for existing sources. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal. Requests shall contain the information specified in paragraphs (h)(5)(iii) through (h)(5)(iv) of this section, as applicable.

(ii) The provisions in § 63.8(f)(5)(i) of subpart A of this part shall govern the review and approval of requests.

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

(A) The requested system shall be designed to:

(1) Measure the operating parameter value at least once every hour.

(2) Record at least 24 values each day during periods of operation.

(3) Record the date and time when monitors are turned off or on.

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

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

(B) The request shall contain a description of the monitoring system and data compression recording system including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all criteria of paragraph (h)(5)(iii)(A) of this section.

(iv) An owner or operator may request approval to use other alternative monitoring systems according to the procedures specified in § 63.8(f) of subpart A of this part.

(6) The owner or operator shall submit the information specified in paragraphs (h)(6)(i) through (h)(6)(iii) of this section, as applicable. For existing sources, this information shall be submitted no later than 18 months prior to the compliance date. For a new source, the information shall be submitted with the application for approval of construction or reconstruction required by § 63.5(d) of subpart A of this part. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units.

(ii) The determination of applicability of this subpart to any storage vessel for which use varies from year to year.

(iii) The determination of applicability of this subpart to any distillation unit for which use varies from year to year.

(i) Recordkeeping.

(1) Each owner or operator subject to the storage vessel provisions in § 63.646 shall keep the records specified in § 63.123 of subpart G of this part except as specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section.

(i) Records related to gaskets, slotted membranes, and sleeve seals are not required for storage vessels within existing sources.

(ii) All references to § 63.122 in § 63.123 of subpart G of this part shall be replaced with § 63.654(e).

(iii) All references to § 63.150 in § 63.123 of subpart G of this part shall be replaced with § 63.652.

(iv) If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

(2) Each owner or operator required to report the results of performance tests under paragraphs (f) and (g)(7) of this section shall retain a record of all reported results as well as a complete test report, as described in paragraph (f)(2)(ii) of this section for each emission point tested.

(3) Each owner or operator required to continuously monitor operating parameters under § 63.644 for miscellaneous process vents or under §§ 63.652 and 63.653 for emission points in an emissions average shall keep the records specified in paragraphs (i)(3)(i) through (i)(3)(v) of this section unless an alternative recordkeeping system has been requested and approved under paragraph (h) of this section.

(i) The monitoring system shall measure data values at least once every hour.

(ii) The owner or operator shall record either:

(A) Each measured data value; or

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

(iii) Daily average values of each continuously monitored parameter shall be calculated for each operating day and retained for 5 years except as specified in paragraph (i)(3)(iv) of this section.

(A) The daily average shall be calculated as the average of all values

for a monitored parameter recorded during the operating day. The average shall cover a 24-hour period if operation is continuous, or the number of hours of operation per day if operation is not continuous.

(B) The operating day shall be the period defined in the Notification of Compliance Status report. It may be from midnight to midnight or another daily period.

(iv) If all recorded values for a monitored parameter during an operating day are within the range established in the Notification of Compliance Status report, the owner or operator may record that all values were within the range and retain this record for 5 years rather than calculating and recording a daily average for that day. For these days, the records required in paragraph (i)(3)(ii) of this section shall also be retained for 5 years.

(v) Monitoring data recorded during periods of monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments shall not be included in any average computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.

(4) All other information required to be reported under paragraphs (a) through (h) of this section shall be retained for 5 years.

§§ 63.655 through 63.679 [Reserved].

Appendix to Subpart CC—Tables

TABLE 1.—HAZARDOUS AIR POLLUTANTS

Chemical name	CAS No. ^a
Benzene	71432
Biphenyl	92524
Butadiene (1,3)	10990
Carbon disulfide	75150

TABLE 1.—HAZARDOUS AIR POLLUTANTS—Continued

Chemical name	CAS No. ^a
Carbonyl sulfide	463581
Cresol (mixed isomers ^b)	1319773
Cresol (m-)	108394
Cresol (o-)	95487
Cresol (p-)	106445
Cumene	98828
Dibromoethane (1,2) (ethylene dibromide)	106934
Dichloroethane (1,2)	107062
Diethanolamine	111422
Ethylbenzene	100414
Ethylene glycol	107211
Hexane	110543
Methanol	67561
Methyl ethyl ketone (2-butanone) ..	78933
Methyl isobutyl ketone (hexone) ..	108101
Methyl tert butyl ether	1634044
Naphthalene	91203
Phenol	108952
Toluene	108883
Trimethylpentane (2,2,4)	540841
Xylene (mixed isomers ^b)	1330207
xylene (m-)	108383
xylene (o-)	95476
xylene (p-)	106423

^a CAS number = Chemical Abstract Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

^b Isomer means all structural arrangements for the same number of atoms of each element and does not mean salts, esters, or derivatives.

TABLE 2.—LEAK DEFINITIONS FOR PUMPS AND VALVES

Standard ^a	Phase	Leak definition (parts per million)
§ 63.163 (pumps)	I	10,000
	II	5,000
	III	2,000
§ 63.168 (valves)	I	10,000
	II	1,000
	III	1,000

^a Subpart H of this part.

TABLE 3.—EQUIPMENT LEAK RECORDKEEPING AND REPORTING REQUIREMENTS FOR SOURCES COMPLYING WITH § 63.648 OF SUBPART CC BY COMPLIANCE WITH SUBPART H OF THIS PART^a

Reference (section of subpart H of this part)	Description	Comment
63.181(a)	Recordkeeping system requirements	Except for §§ 63.181(b)(2)(iii) and 63.181(b)(9).
63.181(b)	Records required for process unit equipment	Except for §§ 63.181(b)(2)(iii) and 63.181(b)(9).
63.181(c)	Visual inspection documentation	Except for §§ 63.181(b)(2)(iii) and 63.181(b)(9).
63.181(d)	Leak detection record requirements	Except for § 63.181(d)(8).
63.181(e)	Compliance requirements for pressure tests for batch product process equipment trains.	This subsection does not apply to subpart CC.
63.181(f)	Compressor compliance test records.	
63.181(g)	Closed-vent systems and control device record requirements.	
63.181(h)	Process unit quality improvement program records.	

TABLE 3.—EQUIPMENT LEAK RECORDKEEPING AND REPORTING REQUIREMENTS FOR SOURCES COMPLYING WITH § 63.648 OF SUBPART CC BY COMPLIANCE WITH SUBPART H OF THIS PART ^a—Continued

Reference (section of subpart H of this part)	Description	Comment
63.181(i)	Heavy liquid service determination record.	Except in § 63.182(2); change "within 90 days of the compliance dates" to "within 150 days of the compliance dates." Except for §§ 63.182 (d)(2)(vii), (d)(2)(viii), and (d)(3).
63.181(j)	Equipment identification record.	
63.181(k)	Enclosed-vented process unit emission limitation record requirements.	
63.182(a)	Reports.	
63.182(b)	Initial notification report requirements.	
63.182(c)	Notification of compliance status report	
63.182(d)	Periodic report	

^a This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

TABLE 4.—GASOLINE DISTRIBUTION EMISSION POINT RECORDKEEPING AND REPORTING REQUIREMENTS ^a

Reference (section of subpart R of this part)	Description	Comment
63.428(b)	Records of test results for each gasoline cargo tank loaded at the facility	Required to be submitted with the periodic report required under 40 CFR part 63 subpart CC.
63.428(c)	Continuous monitoring data recordkeeping requirements	
63.428(g)(1)	Semiannual report loading rack information	
63.428(h)(1) through (h)(3)	Excess emissions report loading rack information	Required to be submitted with the periodic report required under 40 CFR part 63 subpart CC.
63.428(i)	Records and annual reports for facilities meeting § 63.420(c) (emissions screening factor <1.0, but ≥0.5).	The information required under this paragraph is to be submitted with the Periodic Report required under 40 CFR part 63 subpart CC.
63.428(j)	Records and reports for facilities meeting § 63.420(d) (emissions screening factor <0.5).	The information required under this paragraph is to be submitted with the periodic report required under 40 CFR part 63 subpart CC.

^a This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

TABLE 5.—MARINE VESSEL LOADING AND UNLOADING OPERATIONS RECORDKEEPING AND REPORTING REQUIREMENTS ^a

Reference (section of subpart Y of this part)	Description	Comment
63.566(a)	Performance test/site test plan	The information required under this paragraph is to be submitted with the notification of compliance status report required under 40 CFR part 63 subpart CC.
63.566(b)	Performance test data requirements	
63.567(a)	General Provisions (subpart A) applicability	
63.567(c)	Vent system valve bypass recordkeeping requirements	The information required under this paragraph is to be submitted with the periodic report required under 40 CFR part 63 subpart CC.
63.567(d)	Continuous equipment monitoring recordkeeping requirements	
63.567(e)	Flare recordkeeping requirements	
63.567(f)	Quarterly report requirements	
63.567(g)	Marine vessel vapor-tightness documentation	
63.567(h)	Documentation file maintenance	
63.567(i)	Emission estimation reporting and recordkeeping procedures	

^a This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

TABLE 6.—GENERAL PROVISIONS APPLICABILITY TO SUBPART CC ^a

Reference	Applies to subpart CC	Comment
63.1(a)(1)	Yes	
63.1(a)(2)	Yes	
63.1(a)(3)	Yes	

TABLE 6.—GENERAL PROVISIONS APPLICABILITY TO SUBPART CC^a—Continued

Reference	Applies to subpart CC	Comment
63.1(a)(4)	No	Subpart CC (this table) specifies applicability of each paragraph in subpart A to subpart CC.
63.1(a)(5)–63.1(a)(9)	No	
63.1(a)(10)	No	
63.1(a)(11)	Yes	Subpart CC and other cross-referenced subparts specify calendar or operating day.
63.1(a)(12)	Yes	
63.1(a)(13)	Yes	
63.1(a)(14)	Yes	Subpart CC specifies its own applicability.
63.1(b)(1)	No	
63.1(b)(2)	Yes	
63.1(b)(3)	No	Subpart CC explicitly specifies requirements that apply. Area sources are not subject to subpart CC.
63.1(c)(1)	No	
63.1(c)(2)	No	
63.1(c)(3)	No	Except that sources are not required to submit notifications overridden by this table.
63.1(c)(4)	Yes	
63.1(c)(5)	Yes	
63.1(d)	No	§ 63.641 of subpart CC specifies that if the same term is defined in subparts A and CC, it shall have the meaning given in subpart CC.
63.1(e)	No	
63.2	Yes	
63.3	No	Units of measure are spelled out in subpart CC.
63.4(a)(1)–63.4(a)(3)	Yes	
63.4(a)(4)	No	
63.4(a)(5)	Yes	Reserved.
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)(1)	Yes	Except replace term "source" and "stationary source" in § 63.5(a)(1) of subpart A with "affected source."
63.5(a)(2)	Yes	
63.5(b)(1)	Yes	
63.5(b)(2)	No	Reserved.
63.5(b)(3)	Yes	
63.5(b)(4)	Yes	
63.5(b)(5)	Yes	Except the cross-reference to § 63.9(b) is changed to § 63.9(b)(4) and (5). Subpart CC overrides § 63.9 (b)(2) and (b)(3).
63.5(b)(6)	Yes	
63.5(c)	No	
63.5(d)(1)(i)	Yes	Reserved.
63.5(d)(1)(ii)	Yes	
63.5(d)(1)(iii)	No	
63.5(d)(2)	No	Except that the application shall be submitted as soon as practicable before startup but no later than 90 days (rather than 60 days) after the promulgation date of subpart CC if the construction or reconstruction had commenced and initial startup had not occurred before the promulgation of subpart CC.
63.5(d)(3)	Yes	
63.5(d)(4)	Yes	
63.5(e)	Yes	Subpart CC requires submittal of the notification of compliance status report in § 63.654(e).
63.5(f)(1)	Yes	
63.5(f)(2)	Yes	
63.6(a)	Yes	Except § 63.5(d)(3)(ii) does not apply.
63.6(b)(1)	No	
63.6(b)(2)	No	
63.6(b)(3)	Yes	May apply when standards are proposed under section 112(f) of the Clean Air Act.
63.6(b)(4)	No	
63.6(b)(5)	No	
63.6(b)(6)	No	§ 63.654(d) of subpart CC includes notification requirements.
63.6(b)(7)	No	
63.6(c)(1)	No	
63.6(c)(2)–63.6(c)(4)	No	§ 63.640 of subpart CC specifies the compliance date.

TABLE 6.—GENERAL PROVISIONS APPLICABILITY TO SUBPART CC^a—Continued

Reference	Applies to subpart CC	Comment
63.6(c)(5)	Yes	
63.6(d)	No	
63.6(e)	Yes	Does not apply to Group 2 emission points. ^b
63.6(f)(1)	Yes	
63.6(f)(2)(i)	Yes	
63.6(f)(2)(ii)	Yes	Subpart CC specifies the use of monitoring data in determining compliance with subpart CC.
63.6(f)(2)(iii) (A), (B), and (C)	Yes	
63.6(f)(2)(iii)(D)	No	
63.6(f)(2)(iv)	Yes	
63.6(f)(2)(v)	Yes	
63.6(f)(3)	Yes	
63.6(g)	Yes	
63.6(h)	No	Subpart CC does not require opacity and visible emission standards.
63.6(i)	Yes	Except for § 63.6(i)(15), which is reserved.
63.6(j)	Yes	
63.7(a)(1)	No	Subpart CC specifies required testing and compliance demonstration procedures.
63.7(a)(2)	No	Test results must be submitted in the notification of compliance status report due 150 days after compliance date, as specified in § 63.654(d) of subpart CC.
63.7(a)(3)	Yes	
63.7(b)	No	
63.7(c)	No	
63.7(d)	Yes	
63.7(e)(1)	Yes	
63.7(e)(2)	Yes	
63.7(e)(3)	No	Subpart CC specifies test methods and procedures.
63.7(e)(4)	Yes	
63.7(f)	No	Subpart CC specifies applicable methods and provides alternatives.
63.7(g)	No	Performance test reporting specified in § 63.654(d).
63.7(h)(1)	Yes	
63.7(h)(2)	Yes	
63.7(h)(3)	Yes	Yes, except site-specific test plans shall not be required, and where § 63.7(g)(3) specifies submittal by the date the site-specific test plan is due, the date shall be 90 days prior to the notification of compliance status report in § 63.654(d).
63.7(h)(4)	No	
63.7(h)(5)	Yes	
63.8(a)	No	
63.8(b)(1)	Yes	
63.8(b)(2)	No	Subpart CC specifies locations to conduct monitoring.
63.8(b)(3)	Yes	
63.8(c)(1)(i)	Yes	
63.8(c)(1)(ii)	No	Addressed by periodic reports in § 63.654(e) of subpart CC.
63.8(c)(1)(iii)	Yes	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	
63.8(c)(4)	No	Subpart CC specifies monitoring frequency in § 63.641 and § 63.654(g)(3) of subpart CC.
63.8(c)(5)–63.8(c)(8)	No	
63.8(d)	No	
63.8(e)	No	
63.8(f)(1)	Yes	
63.8(f)(2)	Yes	
63.8(f)(3)	Yes	
63.8(f)(4)(i)	No	Timeframe for submitting request is specified in § 63.654(f)(4) of subpart CC.
63.8(f)(4)(ii)	Yes	
63.8(f)(4)(iii)	No	
63.8(f)(5)(i)	Yes	
63.8(f)(5)(ii)	No	
63.8(f)(5)(iii)	Yes	
63.8(f)(6)	No	Subpart CC does not require continuous emission monitors.
63.8(g)	No	Subpart CC specifies data reduction procedures in § 63.654(h)(3).
63.9(a)	Yes	Except that the owner or operator does not need to send a copy of each notification submitted to the Regional Office of the EPA as stated in § 63.9(a)(4)(ii).

TABLE 6.—GENERAL PROVISIONS APPLICABILITY TO SUBPART CC^a—Continued

Reference	Applies to subpart CC	Comment
63.9(b)(1)(i)	No	Specified in § 63.654(d)(2) of subpart CC.
63.9(b)(1)(ii)	No	
63.9(b)(2)	No	An initial notification report is not required under subpart CC.
63.9(b)(3)	No	
63.9(b)(4)	Yes	Except that the notification in § 63.9(b)(4)(i) shall be submitted at the time specified in § 63.654(d)(2) of subpart CC.
63.9(b)(5)	Yes	Except that the notification in § 63.9(b)(5) shall be submitted at the time specified in § 63.654(d)(2) of subpart CC.
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	No	
63.9(f)	No	
63.9(g)	No	
63.9(h)	No	Subpart CC § 63.652(d) specifies notification of compliance status report requirements.
63.9(i)	Yes	
63.9(j)	No	
63.10(a)	Yes	
63.10(b)(1)	No	§ 63.644(d) of subpart CC specifies record retention requirements.
63.10(b)(2)(i)	Yes	
63.10(b)(2)(ii)	Yes	
63.10(b)(2)(iii)	No	
63.10(b)(2)(iv)	Yes	
63.10(b)(2)(v)	Yes	
63.10(b)(2)(vi)–(ix)	No	
63.10(b)(2)(x)	Yes	
63.10(b)(2)(xii)–(xiv)	No	
63.10(b)(3)	No	
63.10(c)	No	
63.10(d)(1)	No	
63.10(d)(2)	No	§ 63.654(d) of subpart CC specifies performance test reporting.
63.10(d)(3)	No	
63.10(d)(4)	Yes	
63.10(d)(5)(i)	Yes ^b	Except that reports required by § 63.10(d)(5)(i) may be submitted at the same time as periodic reports specified in § 63.654(e) of subpart CC.
63.10(d)(5)(ii)	Yes ^b	
63.10(e)	No	
63.10(f)	Yes	
63.11–63.15	Yes	

^a Wherever subpart A specifies "postmark" dates, submittals may be sent by methods other than the U.S. Mail (e.g., by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

^b The plan, and any records or reports of startup, shutdown, and malfunction do not apply to Group 2 emission points.

TABLE 7.—FRACTION MEASURED (F_m), FRACTION EMITTED (F_e), AND FRACTION REMOVED (F_r) FOR HAP COMPOUNDS IN WASTEWATER STREAMS

Chemical name	CAS No. ^a	F_m	F_e	F_r
Benzene	71432	1.00	0.80	0.99
Biphenyl	92524	0.86	0.45	0.99
Butadiene (1,3-)	106990	1.00	0.98	0.99
Carbon disulfide	75150	1.00	0.92	0.99
Cumene	98828	1.00	0.88	0.99
Dichloroethane (1,2-) (Ethylene dichloride)	107062	1.00	0.64	0.99
Ethylbenzene	100414	1.00	0.83	0.99
Hexane	110543	1.00	1.00	0.99
Methanol	67561	0.85	0.17	0.31
Methyl ethyl ketone (2-Butanone)	78933	0.99	0.48	0.95
Methyl isobutyl ketone (Hexone)	108101	0.98	0.53	0.99
Methyl tert-butyl ether	1634044	1.00	0.57	0.99
Naphthalene	91203	0.99	0.51	0.99
Trimethylpentane (2,2,4-)	540841	1.00	1.00	0.99
Xylene (m-)	108383	1.00	0.82	0.99
Xylene (o-)	95476	1.00	0.79	0.99
Xylene (p-)	106423	1.00	0.82	0.99

^a CAS numbers refer to the Chemical Abstracts Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

TABLE 8.—VALUE MONITORING FREQUENCY FOR PHASE III

Performance level	Valve monitoring frequency
Leaking valves ^a (%)	
≥4	Monthly or QIP. ^b
<4	Quarterly.
<3	Semiannual.
<2	Annual.

^a Percent leaking valves is calculated as a rolling average of two consecutive monitoring periods.^b QIP=Quality improvement program. Specified in § 63.175 of subpart H of this part.

TABLE 9.—VALVE MONITORING FREQUENCY FOR ALTERNATIVE

Performance level	Valve monitoring frequency under § 63.649 alternative
Leaking valves ^a (%)	
≥5	Monthly or QIP. ^b
<5	Quarterly.
<4	Semiannual.
<3	Annual.

^a Percent leaking valves is calculated as a rolling average of two consecutive monitoring periods.^b QIP=Quality improvement program. Specified in § 63.175 of subpart H of this part.

TABLE 10.—MISCELLANEOUS PROCESS VENTS—MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAP EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME

Control device	Parameters to be monitored ^a	Recordkeeping and reporting requirements for monitored parameters
Thermal incinerator	Firebox temperature ^b (63.644(a)(1)(i)).	1. Continuous records ^c . 2. Record and report the firebox temperature averaged over the full period of the performance test—NCS ^d . 3. Record the daily average firebox temperature for each operating day ^e . 4. Report all daily average temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected ^f —PR ^g .
Catalytic incinerator	Temperature upstream and downstream of the catalyst bed (63.644(a)(1)(ii)).	1. Continuous records ^c . 2. Record and report the upstream and downstream temperatures and the temperature difference across the catalyst bed averaged over the full period of the performance test—NCS ^d . 3. Record the daily average upstream temperature and temperature difference across the catalyst bed for each operating day ^e . 4. Report all daily average upstream temperatures that are outside the range established in the NCS or operating permit—PR ^g . 5. Report all daily average temperature differences across the catalyst bed that are outside the range established in the NCS or operating permit—PR ^g . 6. Report all operating days when insufficient monitoring data are collected ^f .
Boiler or process heater with a design heat capacity less than 44 megawatts where the vent stream is <i>not</i> introduced into the flame zone ^{h,i} .	Firebox temperature ^b (63.644(a)(4)).	1. Continuous records ^c . 2. Record and report the firebox temperature averaged over the full period of the performance test—NCS ^d . 3. Record the daily average firebox temperature for each operating day ^e . 4. Report all daily average firebox temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected ^f —PR ^g .
Flare	Presence of a flame at the pilot light (63.644(a)(2)).	1. Hourly records of whether the monitor was continuously operating and whether a pilot flame was continuously present during each hour. 2. Record and report the presence of a flame at the pilot light over the full period of the compliance determination—NCS ^d .

TABLE 10.—MISCELLANEOUS PROCESS VENTS—MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAP EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME—Continued

Control device	Parameters to be monitored ^a	Recordkeeping and reporting requirements for monitored parameters
All control devices	<p>Presence of flow diverted to the atmosphere from the control device (63.644(c)(1)) or.</p> <p>Monthly inspections of sealed valves [63.644(c)(2)].</p>	<p>3. Record the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.</p> <p>4. Report the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.</p> <p>1. Hourly records of whether the flow indicator was operating and whether flow was detected at any time during each hour.</p> <p>2. Record and report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating—PR^g.</p> <p>1. Records that monthly inspections were performed.</p> <p>2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed—PR^g.</p>

^a Regulatory citations are listed in parentheses.

^b Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

^c "Continuous records" is defined in § 63.641.

^d NCS = Notification of compliance status report described in § 63.654.

^e The daily average is the average of all recorded parameter values for the operating day. If all recorded values during an operating day are within the range established in the NCS or operating permit, a statement to this effect can be recorded instead of the daily average.

^f When a period of excess emission is caused by insufficient monitoring data, as described in § 63.654(g)(6)(i) (C) or (D), the duration of the period when monitoring data were not collected shall be included in the Periodic Report.

^g PR = Periodic Reports described in § 63.654(g).

^h No monitoring is required for boilers and process heaters with a design heat capacity ≥ 44 megawatts or for boilers and process heaters where all vent streams are introduced into the flame zone. No recordkeeping or reporting associated with monitoring is required for such boilers and process heaters.

ⁱ Process vents that are routed to refinery fuel gas systems are not regulated under this subpart. No monitoring, recordkeeping, or reporting is required for boilers and process heaters that combust refinery fuel gas.

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BILLING CODE 6560-50-P

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

Appendix J Subpart QQQ - Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

§ 60.685

State. In that event, affected facilities within the State will be relieved of the obligation to comply with this section, provided that they comply with the requirements established by the State.

§ 60.685 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall conduct performance tests while the product with the highest loss on ignition (LOI) expected to be produced by the affected facility is being manufactured.

(c) The owner or operator shall determine compliance with the particulate matter standard in § 60.682 as follows:

(1) The emission rate (E) of particulate matter shall be computed for each run using the following equation:

$$E = (C_i Q_{sd}) / (P_{avg} K)$$

where:

E = emission rate of particulate matter, kg/Mg (lb/ton).

C_i = concentration of particulate matter, g/dscm (gr/dscf).

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

P_{avg} = average glass pull rate, Mg/hr (ton/hr).

K = 1,000 g/kg (7,000 gr/lb).

(2) Method 5E shall be used to determine the particulate matter concentration (C_i) and the volumetric flow rate (Q_{sd}) of the effluent gas. The sampling time and sample volume shall be at least 120 minutes and 2.55 dscm (90.1 dscf).

(3) The average glass pull rate (P_{avg}) for the manufacturing line shall be the arithmetic average of three glass pull rate (P_i) determinations taken at intervals of at least 30 minutes during each run.

The individual glass pull rates (P_i) shall be computed using the following equation:

$$P_i = K' L_s W_m M [1.0 - (LOI/100)]$$

where:

P_i = glass pull rate at interval "i", Mg/hr (ton/hr).

L_s = line speed, m/min (ft/min).

W_m = trimmed mat width, m (ft).

M = mat gram weight, g/m² (lb/ft²).

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LOI = loss on ignition, weight percent.

K' = conversion factor, 6 × 10⁻⁵ (min-Mg)/(hr-g) [3 × 10⁻² (min-ton)/(hr-lb)].

(i) ASTM D2584-68 (Reapproved 1985) or 94 (incorporated by reference—see § 60.17), shall be used to determine the LOI for each run.

(ii) Line speed (L_s), trimmed mat width (W_m), and mat gram weight (M) shall be determined for each run from the process information or from direct measurements.

(d) To comply with § 60.684(d), the owner or operator shall record measurements as required in § 60.684 (a) and (b) using the monitoring devices in § 60.683 (a) and (b) during the particulate matter runs.

[54 FR 6680, Feb. 14, 1989, as amended at 65 FR 61778, Oct. 17, 2000]

Subpart QQQ—Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems

SOURCE: 53 FR 47623, Nov. 23, 1988, unless otherwise noted.

§ 60.690 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987.

(2) An individual drain system is a separate affected facility.

(3) An oil-water separator is a separate affected facility.

(4) An aggregate facility is a separate affected facility.

(b) Notwithstanding the provisions of 40 CFR 60.14(e)(2), the construction or installation of a new individual drain system shall constitute a modification to an affected facility described in § 60.690(a)(4). For purposes of this paragraph, a new individual drain system shall be limited to all process drains and the first common junction box.

§ 60.691 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of 40 CFR part 60, and the following

terms shall have the specific meanings given them.

Active service means that a drain is receiving refinery wastewater from a process unit that will continuously maintain a water seal.

Aggregate facility means an individual drain system together with ancillary downstream sewer lines and oil-water separators, down to and including the secondary oil-water separator, as applicable.

Catch basin means an open basin which serves as a single collection point for stormwater runoff received directly from refinery surfaces and for refinery wastewater from process drains.

Closed vent system means a system that is not open to the atmosphere and that is composed of piping, connections, and, if necessary, flow-inducing devices that transport gas or vapor from an emission source to a control device. If gas or vapor from regulated equipment are routed to a process (e.g., to a petroleum refinery fuel gas system), the process shall not be considered a closed vent system and is not subject to the closed vent system standards.

Completely closed drain system means an individual drain system that is not open to the atmosphere and is equipped and operated with a closed vent system and control device complying with the requirements of § 60.692-5.

Control device means an enclosed combustion device, vapor recovery system or flare.

Fixed roof means a cover that is mounted to a tank or chamber in a stationary manner and which does not move with fluctuations in wastewater levels.

Floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface.

Gas-tight means operated with no detectable emissions.

Individual drain system means all process drains connected to the first common downstream junction box. The term includes all such drains and common junction box, together with their associated sewer lines and other junction boxes, down to the receiving oil-water separator.

Junction box means a manhole or access point to a wastewater sewer system line.

No detectable emissions means less than 500 ppm above background levels, as measured by a detection instrument in accordance with Method 21 in appendix A of 40 CFR part 60.

Non-contact cooling water system means a once-through drain, collection and treatment system designed and operated for collecting cooling water which does not come into contact with hydrocarbons or oily wastewater and which is not recirculated through a cooling tower.

Oil-water separator means wastewater treatment equipment used to separate oil from water consisting of a separation tank, which also includes the forebay and other separator basins, skimmers, weirs, grit chambers, and sludge hoppers. Slop oil facilities, including tanks, are included in this term along with storage vessels and auxiliary equipment located between individual drain systems and the oil-water separator. This term does not include storage vessels or auxiliary equipment which do not come in contact with or store oily wastewater.

Oily wastewater means wastewater generated during the refinery process which contains oil, emulsified oil, or other hydrocarbons. Oily wastewater originates from a variety of refinery processes including cooling water, condensed stripping steam, tank draw-off, and contact process water.

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

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation of petroleum, cracking, or reforming unfinished petroleum derivatives.

Sewer line means a lateral, trunk line, branch line, ditch, channel, or other conduit used to convey refinery wastewater to downstream components of a refinery wastewater treatment system. This term does not include buried, below-grade sewer lines.

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Slop oil means the floating oil and solids that accumulate on the surface of an oil-water separator.

Storage vessel means any tank, reservoir, or container used for the storage of petroleum liquids, including oily wastewater.

Stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting stormwater and which is segregated from the process wastewater collection system.

Wastewater system means any component, piece of equipment, or installation that receives, treats, or processes oily wastewater from petroleum refinery process units.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water that has a design capability to create a water barrier between the sewer and the atmosphere.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995]

§ 60.692-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction.

(b) Compliance with §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.696.

(c) Permission to use alternative means of emission limitation to meet the requirements of §§ 60.692-2 through 60.692-4 may be granted as provided in § 60.694.

(d)(1) Stormwater sewer systems are not subject to the requirements of this subpart.

(2) Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.

(3) Non-contact cooling water systems are not subject to the requirements of this subpart.

(4) An owner or operator shall demonstrate compliance with the exclusions in paragraphs (d)(1), (2), and (3) of

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this section as provided in § 60.697 (h), (i), and (j).

§ 60.692-2 Standards: Individual drain systems.

(a)(1) Each drain shall be equipped with water seal controls.

(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.

(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.

(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in § 60.692-6.

(b)(1) Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(2) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(3) Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(4) If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in § 60.692-6.

(c)(1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no

visual gaps or cracks in joints, seals, or other emission interfaces.

(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.

(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in § 60.692-6.

(d) Except as provided in paragraph (e) of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section.

(e) Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

§ 60.692-3 Standards: Oil-water separators.

(a) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in § 60.693-2.

(1) The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.

(2) The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.

(3) If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.

(4) Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall

and that access doors and other openings are closed and gasketed properly.

(5) When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in § 60.692-6.

(b) Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph (a) of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of § 60.692-5, except as provided in paragraph (c) of this section or in § 60.693-2.

(c)(1) Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of paragraph (b) of this section, but shall meet the requirements of paragraph (a) of this section, or may elect to comply with paragraph (c)(2) of this section.

(2) The owner or operator may elect to comply with the requirements of paragraph (a) of this section for the existing fixed roof covering a portion of the separator tank and comply with the requirements for floating roofs in § 60.693-2 for the remainder of the separator tank.

(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in §§ 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

(e) Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed

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roof meeting the requirements of paragraph (a) of this section.

(f) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph (a) of this section, and not paragraph (b) of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

§ 60.692-4 Standards: Aggregate facility.

A new, modified, or reconstructed aggregate facility shall comply with the requirements of §§ 60.692-2 and 60.692-3.

§ 60.692-5 Standards: Closed vent systems and control devices.

(a) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C (1,500 °F).

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.

(c) Flares used to comply with this subpart shall comply with the requirements of 40 CFR 60.18.

(d) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(e)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in § 60.696.

(2) Closed vent systems shall be purged to direct vapor to the control device.

(3) A flow indicator shall be installed on a vent stream to a control device to

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ensure that the vapors are being routed to the device.

(4) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(5) When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in § 60.692-6.

§ 60.692-6 Standards: Delay of repair.

(a) Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown.

(b) Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

§ 60.692-7 Standards: Delay of compliance.

(a) Delay of compliance of modified individual drain systems with ancillary downstream treatment components will be allowed if compliance with the provisions of this subpart cannot be achieved without a refinery or process unit shutdown.

(b) Installation of equipment necessary to comply with the provisions of this subpart shall occur no later than the next scheduled refinery or process unit shutdown.

§ 60.693-1 Alternative standards for individual drain systems.

(a) An owner or operator may elect to construct and operate a completely closed drain system.

(b) Each completely closed drain system shall be equipped and operated with a closed vent system and control device complying with the requirements of § 60.692-5.

(c) An owner or operator must notify the Administrator in the report required in 40 CFR 60.7 that the owner or operator has elected to construct and operate a completely closed drain system.

(d) If an owner or operator elects to comply with the provisions of this section, then the owner or operator does

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not need to comply with the provisions of § 60.692-2 or § 60.694.

(e)(1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.

(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in § 60.692-6.

§ 60.693-2 Alternative standards for oil-water separators.

(a) An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.

(1) Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.

(i) The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.

(A) A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(B) The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.

(C) The total gap area between the primary seal and the separator wall shall not exceed 67 cm²/m (3.2 in.²/ft) of separator wall perimeter.

(ii) The secondary seal shall be above the primary seal and cover the annular

space between the floating roof and the wall of the separator.

(A) The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

(B) The total gap area between the secondary seal and the separator wall shall not exceed 6.7 cm²/m (0.32 in.²/ft) of separator wall perimeter.

(iii) The maximum gap width and total gap area shall be determined by the methods and procedures specified in § 60.696(d).

(A) Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.

(B) Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.

(iv) The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs (a)(1) (i) and (ii) of this section.

(2) Except as provided in paragraph (a)(4) of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.

(3) The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).

(4) The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.

(5)(i) Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.

(ii) When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as

practicable, but not later than 30 calendar days after it is identified, except as provided in § 60.692-6.

(b) An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph (a) of this section.

(c) For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of § 60.692-3(a) shall be installed.

(d) Except as provided in paragraph (c) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of §§ 60.692-3 or 60.694 applicable to the same facilities.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995]

§ 60.694 Permission to use alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved by the applicable requirement in § 60.692, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

§ 60.695 Monitoring of operations.

(a) Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or

requirements are approved for that facility by the Administrator.

(1) Where a thermal incinerator is used for VOC emission reduction, a temperature monitoring device equipped with a continuous recorder shall be used to measure the temperature of the gas stream in the combustion zone of the incinerator. The temperature monitoring device shall have an accuracy of ± 1 percent of the temperature being measured, expressed in $^{\circ}\text{C}$, or ± 0.5 $^{\circ}\text{C}$ (0.9 $^{\circ}\text{F}$), whichever is greater.

(2) Where a catalytic incinerator is used for VOC emission reduction, temperature monitoring devices, each equipped with a continuous recorder shall be used to measure the temperature in the gas stream immediately before and after the catalyst bed of the incinerator. The temperature monitoring devices shall have an accuracy of ± 1 percent of the temperature being measured, expressed in $^{\circ}\text{C}$, or ± 0.5 $^{\circ}\text{C}$ (0.9 $^{\circ}\text{F}$), whichever is greater.

(3) Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(i) For a carbon adsorption system that regenerates the carbon bed directly onsite, a monitoring device that continuously indicates and records the volatile organic compound concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to

conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

(4) Where a flare is used for VOC emission reduction, the owner or operator shall comply with the monitoring requirements of 40 CFR 60.18(f)(2).

(b) Where a VOC recovery device other than a carbon adsorber is used to meet the requirements specified in § 60.692-5(a), the owner or operator shall provide to the Administrator information describing the operation of the control device and the process parameter(s) that would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

(c) An alternative operational or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

§ 60.696 Performance test methods and procedures and compliance provisions.

(a) Before using any equipment installed in compliance with the requirements of § 60.692-2, § 60.692-3, § 60.692-4, § 60.692-5, or § 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(b) The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.692-5 (other than a flare) is exempt from § 60.8 of the General Provisions and shall use Method 21 to

measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

(1) Zero air (less than 10 ppm of hydrocarbon in air), and

(2) A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(c) The owner or operator shall conduct a performance test initially, and at other times as requested by the Administrator, using the test methods and procedures in § 60.18(f) to determine compliance of flares.

(d) After installing the control equipment required to meet § 60.693-2(a) or whenever sources that have ceased to treat refinery wastewater for a period of 1 year or more are placed back into service, the owner or operator shall determine compliance with the standards in § 60.693-2(a) as follows:

(1) The maximum gap widths and maximum gap areas between the primary seal and the separator wall and between the secondary seal and the separator wall shall be determined individually within 60 calendar days of the initial installation of the floating roof and introduction of refinery wastewater or 60 calendar days after the equipment is placed back into service using the following procedure when the separator is filled to the design operating level and when the roof is floating off the roof supports.

(i) Measure seal gaps around the entire perimeter of the separator in each place where a 0.32 cm (0.125 in.) diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the separator and measure the gap width and perimetrical distance of each such location.

(ii) The total surface area of each gap described in (d)(1)(i) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the wall to the seal and multiplying each such width by its respective perimetrical distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually, divide

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the sum for each seal by the nominal perimeter of the separator basin and compare each to the maximum gap area as specified in § 60.693-2.

(2) The gap widths and total gap area shall be determined using the procedure in paragraph (d)(1) of this section according to the following frequency:

(i) For primary seals, once every 5 years.

(ii) For secondary seals, once every year.

§ 60.697 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

(b)(1) For individual drain systems subject to § 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

(2) For junction boxes subject to § 60.692-2, the location, date, and corrective action shall be recorded for inspections required by § 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(3) For sewer lines subject to §§ 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by §§ 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

(c) For oil-water separators subject to § 60.692-3, the location, date, and corrective action shall be recorded for inspections required by § 60.692-3(a) when a problem is identified that could result in VOC emissions.

(d) For closed vent systems subject to § 60.692-5 and completely closed drain systems subject to § 60.693-1, the location, date, and corrective action shall be recorded for inspections required by § 60.692-5(e) during which detectable emissions are measured or a

problem is identified that could result in VOC emissions.

(e)(1) If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

(2) The reason for the delay as specified in § 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.

(3) The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.

(4) The date of successful repair or corrective action shall be recorded.

(f)(1) A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.

(2) The following information pertaining to the design specifications shall be kept.

(i) Detailed schematics, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(3) The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

(ii) For a carbon adsorption system that does not regenerate the carbon

bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(iii) Periods when the closed vent systems and control devices required in § 60.692 are not operated as designed, including periods when a flare pilot does not have a flame shall be recorded and kept for 2 years after the information is recorded.

(iv) Dates of startup and shutdown of the closed vent system and control devices required in § 60.692 shall be recorded and kept for 2 years after the information is recorded.

(v) The dates of each measurement of detectable emissions required in §§ 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.

(vi) The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.

(vii) The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.

(viii) Each owner or operator of an affected facility that uses a thermal incinerator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature, and shall keep such records for 2 years after the information is recorded.

(ix) Each owner or operator of an affected facility that uses a catalytic incinerator shall maintain continuous records of the temperature of the gas

stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference, and shall keep such records for 2 years after the information is recorded.

(x) Each owner or operator of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(A) Each owner or operator of an affected facility that uses a carbon adsorber which is regenerated directly onsite shall maintain continuous records of the volatile organic compound concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(B) If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

(g) If an owner or operator elects to install a tightly sealed cap or plug over

a drain that is out of active service, the owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which indicate the location of such drains.

(h) For stormwater sewer systems subject to the exclusion in § 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

(i) For ancillary equipment subject to the exclusion in § 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.

(j) For non-contact cooling water systems subject to the exclusion in § 60.692-1(d)(3), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

(k) For oil-water separators subject to § 60.693-2, the location, date, and corrective action shall be recorded for inspections required by §§ 60.693-2(a)(1)(iii)(A) and (B), and shall be maintained for the time period specified in paragraphs (k)(1) and (2) of this section.

(1) For inspections required by § 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.

(2) For inspections required by § 60.693-2(a)(1)(iii)(B), two years after the information is recorded.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

§ 60.698 Reporting requirements.

(a) An owner or operator electing to comply with the provisions of § 60.693 shall notify the Administrator of the alternative standard selected in the report required in § 60.7.

(b)(1) Each owner or operator of a facility subject to this subpart shall sub-

mit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

(2) Each owner or operator of an affected facility that uses a flare shall submit to the Administrator within 60 days after initial startup, as required under § 60.8(a), a report of the results of the performance test required in § 60.696(c).

(c) A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.

(d) As applicable, a report shall be submitted semiannually to the Administrator that indicates:

(1) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(2) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as

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measured by the temperature monitoring device, is less than 80 percent of the design temperature difference, or,

(3) Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

(i) Each 3-hour period of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases from a carbon adsorber which is regenerated directly onsite is more than 20 percent greater than the design exhaust gas concentration level or reading.

(ii) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in § 60.695(a)(3)(ii).

(e) If compliance with the provisions of this subpart is delayed pursuant to § 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43260, Aug. 18, 1995]

§ 60.699 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States:

§ 60.694 Permission to use alternative means of emission limitations.

[53 FR 47623, Nov. 23, 1985]

Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

SOURCE: 58 FR 45962, Aug. 31, 1993, unless otherwise noted.

§ 60.700 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in § 60.707 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after June 29, 1990:

(1) Each reactor process not discharging its vent stream into a recovery system.

(2) Each combination of a reactor process and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any reactor process that is designed and operated as a batch operation is not an affected facility.

(2) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§ 60.702(c); 60.704 (d), (e), and (f); and 60.705 (g), (1)(1), (1)(6), and (n).

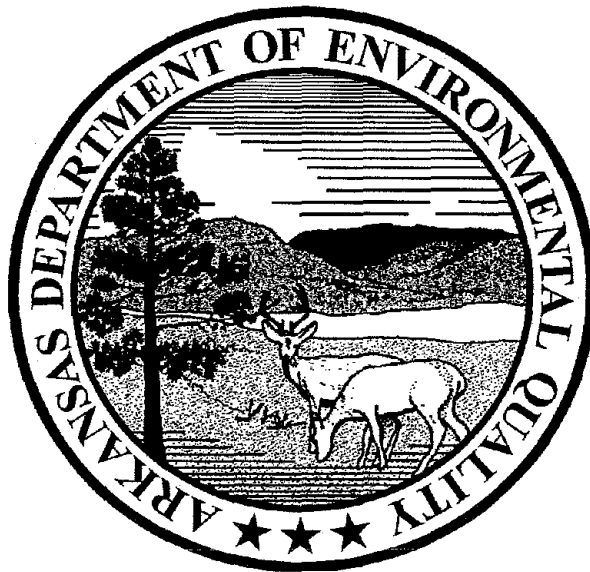
(3) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than 1 gigagram per year (1,100 tons per year) is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in § 60.705 (i), (1)(5), and (n).

(4) Each affected facility operated with a vent stream flow rate less than

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**Appendix K Arkansas Department of Environmental Quality Continuous Emission Monitoring
Systems Conditions**

Arkansas Department of Environmental Quality



CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised August 2004

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS)/(COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63 or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.
- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the RATA, RAA, or CGA which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value - The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

- A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.
- B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.
- C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PSTs for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.
- D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval the excess zero and span drifts measured must be quantified and recorded.
- E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.
- F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.
- F. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.
- H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
- J. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

- A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.
- B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.
- C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.
- D. Except for Part 75 CEMs, each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.
- E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.
- F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.
- G. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

- A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.
- B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.
- C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:
1. Calibration of CEMS/COMS
 - a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
 2. Calibration drift determination and adjustment of CEMS/COMS
 - a. Out-of-control period determination
 - b. Steps of corrective action
 3. Preventive maintenance of CEMS/COMS
 - a. CEMS/COMS information
 - 1) Manufacture
 - 2) Model number
 - 3) Serial number
 - b. Scheduled activities (check list)
 - c. Spare part inventory
 4. Data recording, calculations, and reporting
 5. Accuracy audit procedures including sampling and analysis methods
 6. Program of corrective action for malfunctioning CEMS/COMS
- D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O ₂ & CO ₂)	> 1.0 % O ₂ or CO ₂
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O ₂ & CO ₂)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O ₂ & CO ₂)	> 15% of the three run average or > 7.5 % of the applicable standard

- F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.
- G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

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Appendix M Subpart UUU - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

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agencies are as specified in paragraphs (c) (1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.1541, 63.1543(a) through (c), (f) through (g), and 63.1544 through 63.1545.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37360, June 23, 2003]

TABLE 1 TO SUBPART TTT OF PART 63—SUMMARY OF MONITORING REQUIREMENTS FOR NEW AND EXISTING AFFECTED SOURCES AND EMISSION UNITS

Reference	Applies to subpart TTT	Comment
§63.1	Yes	
§63.2	Yes	
§63.3	Yes	
§63.4	Yes	
§63.5	Yes	
§63.6(a), (b), (c), (e), (f), (g), (i) and (j)	Yes	
§63.6(d) and (h)	No	No opacity limits in rule.
§63.7	Yes	
§63.8	Yes	
§63.9 (a), (b), (c), (d), (e), (g), (h)(1) through (3), (h)(5) and (6), (i) and (j).	Yes	
§63.9(f) and (h)(4)	No	No opacity or visible emission limits in rule.
§63.10	Yes	
§63.11	No	Flares will not be used to comply with the emission limits.
§63.12 through 63.15	Yes	

Subpart UUU—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

SOURCE: 67 FR 17773, Apr. 11, 2002, unless otherwise noted.

WHAT THIS SUBPART COVERS

§63.1560 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (HAP) emitted from petroleum refineries. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§63.1561 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a petroleum refinery that is located at a major source of HAP emissions.

(1) A petroleum refinery is an establishment engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code 2911 and the North American Industry Classification (NAIC) code 32411, and used mainly for:

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

(ii) Separating petroleum; or

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

(2) A major source of HAP is a plant site that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year

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or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

(b) [Reserved]

§63.1562 What parts of my plant are covered by this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source at a petroleum refinery.

(b) The affected sources are:

(1) The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit (i.e., the catalyst regeneration flue gas vent).

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

(3) The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants, that are associated with sulfur recovery.

(4) Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

(c) An affected source is a new affected source if you commence construction of the affected source after September 11, 1998, and you meet the applicability criteria in §63.1561 at the time you commenced construction.

(d) Any affected source is reconstructed if you meet the criteria in §63.2.

(e) An affected source is existing if it is not new or reconstructed.

(f) This subpart does not apply to:

(1) A thermal catalytic cracking unit.

(2) A sulfur recovery unit that does not recover elemental sulfur or where

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the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur (e.g., the LO-CAT II process).

(3) A redundant sulfur recovery unit not located at a petroleum refinery and used by the refinery only for emergency or maintenance backup.

(4) Equipment associated with bypass lines such as low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons.

(5) Gaseous streams routed to a fuel gas system.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005]

§63.1563 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) If you startup your affected source before April 11, 2002, then you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002.

(2) If you startup your affected source after April 11, 2002, you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the emission limitations and work practice standards for existing affected sources in this subpart by no later than April 11, 2005 except as specified in paragraph (c) of this section.

(c) We will grant an extension of compliance for an existing catalytic cracking unit allowing additional time to meet the emission limitations and work practice standards for catalytic cracking units in §§63.1564 and 63.1565 if you commit to hydrotreating the catalytic cracking unit feedstock and to meeting the emission limitations of this subpart on the same date that your facility meets the final Tier 2 gasoline sulfur control standard (40 CFR

part 80, subpart J). To obtain an extension, you must submit a written notification to your permitting authority according to the requirements in §63.1574(e). Your notification must include the information in paragraphs (c)(1) and (2) of this section.

(1) Identification of the affected source with a brief description of the controls to be installed (if needed) to comply with the emission limitations for catalytic cracking units in this subpart.

(2) A compliance schedule, including the information in paragraphs (c)(2)(i) through (iv) of this section.

(i) The date by which onsite construction or the process change is to be initiated.

(ii) The date by which onsite construction or the process change is to be completed.

(iii) The date by which your facility will achieve final compliance with both the final Tier 2 gasoline sulfur control standard as specified in §80.195, and the emission limitations and work practice standards for catalytic cracking units in this subpart. In no case will your permitting authority grant an extension beyond the date you are required to meet the Tier 2 gasoline sulfur control standard or December 31, 2009, whichever comes first. If you don't comply with the emission limitations and work practice standards for existing catalytic cracking units by the specified date, you will be out-of-compliance with the requirements for catalytic cracking units beginning April 11, 2005.

(iv) A brief description of interim emission control measures that will be taken to ensure proper operation and maintenance of the process equipment during the period of the compliance extension.

(d) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the requirements in paragraphs (d)(1) and (2) of this section apply.

(1) Any portion of the existing facility that is a new affected source or a new reconstructed source must be in compliance with the requirements of this subpart upon startup.

(2) All other parts of the source must be in compliance with the requirements of this subpart by no later than 3 years after it becomes a major source or, if applicable, the extended compliance date granted according to the requirements in paragraph (c) of this section.

(e) You must meet the notification requirements in §63.1574 according to the schedule in §63.1574 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart.

CATALYTIC CRACKING UNITS, CATALYTIC REFORMING UNITS, SULFUR RECOVERY UNITS, AND BYPASS LINES

§63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in §60.102 of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn't subject to the NSPS for PM, you can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to comply with the NSPS requirements (Option 1);

(ii) You can elect to comply with the PM emission limit (Option 2);

(iii) You can elect to comply with the Nickel (Ni) lb/hr emission limit (Option 3); or

(iv) You can elect to comply with the Ni lb/1,000 lbs of coke burn-off emission limit (Option 4).

(2) Comply with each operating limit in Table 2 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for metal HAP emissions from catalytic cracking units required

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in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in § 63.1575(j).

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:*

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in § 63.1572 and Table 3 of this subpart.

(2) Conduct a performance test for each catalytic cracking unit not subject to the NSPS for PM according to the requirements in § 63.1571 and under

the conditions specified in Table 4 of this subpart.

(3) Establish each site-specific operating limit in Table 2 of this subpart that applies to you according to the procedures in Table 4 of this subpart.

(4) Use the procedures in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) If you elect Option 1 in paragraph (a)(1)(i) of this section, the NSPS requirements, compute the PM emission rate (lb/1,000 lbs of coke burn-off) for each run using Equations 1, 2, and 3 (if applicable) of this section as follows:

$$R_c = K_1 Q_e (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_e [(\%CO/2) + \%CO_2 + \%O_2] + K_3 Q_{oxy} (\%O_{xy}) \quad (\text{Eq. 1})$$

Where:

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

Q_e = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams. Example: You may measure upstream or downstream of an electrostatic precipitator, but you must measure upstream of a carbon monoxide boiler, dscm/min (dscf/min). You may use the alternative in either § 63.1573(a)(1) or (a)(2), as applicable, to calculate Q_e ;

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

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

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

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

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

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

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

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

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

$$E = \frac{K \times C_s \times Q_{sd}}{R_c} \quad (\text{Eq. 2})$$

Where:

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

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

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

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

K = Conversion factor, 1.0 (kg²/g)/(1,000 kg (1,000 lb/(1,000 lb))).

$$E_s = 1.0 + A(H/R_c)K' \quad (\text{Eq. 3})$$

Where:

E_s = Emission rate of PM allowed, kg/1,000 kg (lb/1,000 lb) of coke burn-off in catalyst regenerator;

1.0 = Emission limitation, kg coke/1,000 kg (lb coke/1,000 lb);

A = Allowable incremental rate of PM emissions, 0.18 g/million cal (0.10 lb/million Btu); and

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr). Make sure your permitting authority approves procedures for determining the heat input rate.

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr) determined using Equation 1 of this section; and

K' = Conversion factor to units to standard, 1.0 (kg²/g)/(1,000 kg (10³ lb/(1,000 lb))).

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(ii) If you elect Option 2 in paragraph (a)(1)(ii) of this section, the PM emission limit, compute your PM emission rate (lb/1,000 lbs of coke burn-off) using Equations 1 and 2 of this section and

your site-specific opacity operating limit (if you use a continuous opacity monitoring system) using Equation 4 of this section as follows:

$$\text{Opacity Limit} = \text{Opacity}_{st} \times \left(\frac{1 \text{ lb/klb coke burn}}{\text{PMEmR}_{st}} \right) \quad (\text{Eq. 4})$$

Where:

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

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

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

$$E_{Ni_1} = C_{Ni} \times Q_{sd} \quad (\text{Eq. 5})$$

(iii) If you elect Option 3 in paragraph (a)(1)(iii) of this section, the Ni lb/hr emission limit, compute your Ni

emission rate using Equation 5 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 6 and 7 of this section as follows:

Where:

E_{Ni1} = Mass emission rate of Ni, mg/hr (lb/hr); and

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

$$\text{Opacity}_1 = \frac{13 \text{ g Ni/hr}}{\text{NiEmR1}_{st}} \times \text{Opacity}_{st} \quad (\text{Eq. 6})$$

Where:

Opacity₁ = Opacity value for use in Equation 7 of this section, percent, or 10 percent, whichever is greater; and

NiEmR_{1st} = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each of the performance test runs, g Ni/hr.

$$\text{Ni Operating Limit}_1 = \text{Opacity}_1 \times Q_{mon,st} \times E\text{-Cat}_{st} \quad (\text{Eq. 7})$$

Where:

Ni operating limit₁ = Maximum permissible hourly average Ni operating limit, percent-acfm-ppmw, i.e., your site-specific Ni operating limit;

Q_{mon,st} = Hourly average actual gas flow rate as measured by the continuous parameter monitoring system during the performance test or using the alternative procedure in §63.1573, acfm; and

E-Cat_{st} = Ni concentration on equilibrium catalyst measured during source test, ppmw.

(iv) If you elect Option 4 in paragraph (a)(1)(iv) of this section, the Ni lbs/1,000

lbs of coke burn-off emission limit, compute your Ni emission rate using Equations 1 and 8 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 9 and 10 of this section as follows:

$$E_{Ni2} = \frac{C_{Ni} \times Q_{sd}}{R_c} \quad (\text{Eq. 8})$$

Where:

E_{Ni2} = Normalized mass emission rate of Ni, mg/kg coke (lb/1,000 lbs coke).

$$\text{Opacity}_2 = \frac{1.0 \text{ mg/kg coke}}{\text{NiEmR2}_{st}} \times \text{Opacity}_{st} \quad (\text{Eq. 9})$$

Where:

Opacity_2 = Opacity value for use in Equation 10 of this section, percent, or 10 percent, whichever is greater; and

NiEmR2_{st} = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of this section for each of the performance test runs, mg/kg coke.

$$\text{Ni Operating Limit}_2 = \text{Opacity}_2 \times \text{E-Cat}_{st} \times \frac{Q_{\text{mon},st}}{R_{c,st}} \quad (\text{Eq. 10})$$

Where:

$\text{Ni operating limit}_2$ = Maximum permissible hourly average Ni operating limit, percent-ppmw-acfm-hr/kg coke, i.e., your site-specific Ni operating limit; and

$R_{c,st}$ = Coke burn rate from Equation 1 of this section, as measured during the initial performance test, kg coke/hr.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 5 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting your operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:*

(1) Demonstrate continuous compliance with each emission limitation in Tables 1 and 2 of this subpart that applies to you according to the methods specified in Tables 6 and 7 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance, and monitoring plan.

(3) If you use a continuous opacity monitoring system and elect to comply with Option 3 in paragraph (a)(1)(iii) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 11 of this section as follows:

$$\text{Ni Operating Value}_1 = \text{Opacity} \times Q_{\text{mon}} \times \text{E-Cat} \quad (\text{Eq. 11})$$

Where:

$\text{Ni operating value}_1$ = Maximum permissible hourly average Ni standard operating value, %-acfm-ppmw;

Opacity = Hourly average opacity, percent;

Q_{mon} = Hourly average actual gas flow rate as measured by continuous parameter monitoring system or calculated by alternative procedure in § 63.1573, acfm; and

E-Cat = Ni concentration on equilibrium catalyst from weekly or more recent measurement, ppmw.

(4) If you use a continuous opacity monitoring system and elect to comply with Option 4 in paragraph (a)(1)(iv) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 12 of this section as follows:

$$\text{Ni Operating Value}_2 = \frac{\text{Opacity} \times E - \text{Cat} \times Q_{\text{mon}}}{R_c} \quad (\text{Eq. 12})$$

Where:

Ni operating value₂ = Maximum permissible hourly average Ni standard operating value, percent-acfm-ppmw-hr/kg coke.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005]

§ 63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(a) *What emission limitations and work practice standards must I meet? You must:*

(1) Meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in § 60.103 of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn't subject to the NSPS for CO, you can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to comply with the NSPS requirements (Option 1); or

(ii) You can elect to comply with the CO emission limit (Option 2).

(2) Comply with each site-specific operating limit in Table 9 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in § 63.1575(j).

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:*

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in § 63.1572 and Table 10 of this subpart. Except:

(i) Whether or not your catalytic cracking unit is subject to the NSPS

for CO in § 60.103 of this chapter, you don't have to install and operate a continuous emission monitoring system if you show that CO emissions from your vent average less than 50 parts per million (ppm), dry basis. You must get an exemption from your permitting authority, based on your written request. To show that the emissions average is less than 50 ppm (dry basis), you must continuously monitor CO emissions for 30 days using a CO continuous emission monitoring system that meets the requirements in § 63.1572.

(ii) If your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent emissions to a boiler (including a "CO boiler") or process heater that has a design heat input capacity of at least 44 megawatts (MW).

(iii) If your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent emissions to a boiler or process heater in which all vent streams are introduced into the flame zone.

(2) Conduct each performance test for a catalytic cracking unit not subject to the NSPS for CO according to the requirements in § 63.1571 and under the conditions specified in Table 11 of this subpart.

(3) Establish each site-specific operating limit in Table 9 of this subpart that applies to you according to the procedures in Table 11 of this subpart.

(4) Demonstrate initial compliance with each emission limitation that applies to you according to Table 12 of this subpart.

(5) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance,

and monitoring plan to your permitting authority as part of your Notification of Compliance Status according to § 63.1574.

(6) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 8 and 9 of this subpart that applies to you according to the methods specified in Tables 13 and 14 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

§ 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to vent emissions of total organic compounds (TOC) to a flare that meets the control device requirements in § 63.11(b) (Option 1); or

(ii) You can elect to meet a TOC or nonmethane TOC percent reduction standard or concentration limit, whichever is less stringent (Option 2).

(2) Comply with each site-specific operating limit in Table 16 of this subpart that applies to you.

(3) Except as provided in paragraph (a)(4) of this section, the emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents associated with initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. The emission limitations in Tables 15 and 16 of this subpart do not apply to the coke burn-off, catalyst rejuvenation,

reduction or activation vents, or to the control systems used for these vents.

(4) The emission limitations in Tables 15 and 16 of this subpart do not apply to emissions from process vents during depressuring and purging operations when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less.

(5) Prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in § 63.1572 and Table 17 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in § 63.1571 and under the conditions specified in Table 18 of this subpart.

(3) Establish each site-specific operating limit in Table 16 of this subpart that applies to you according to the procedures in Table 18 of this subpart.

(4) Use the procedures in paragraph (b)(4)(i) or (ii) of this section to determine initial compliance with the emission limitations.

(i) If you elect the percent reduction standard under Option 2, calculate the emission rate of nonmethane TOC using Equation 1 of this section (if you use Method 25) or Equation 2 of this section (if you use Method 25A or Methods 25A and 18), then calculate the mass emission reduction using Equation 3 of this section as follows:

$$E = K_4 M_c Q_s \quad (\text{Eq. 1})$$

Where:

E = Emission rate of nonmethane TOC in the vent stream, kilograms-C per hour;

K_4 = Constant, 6.0×10^{-5} (kilograms per milligram)(minutes per hour);

M_c = Mass concentration of total gaseous nonmethane organic (as carbon) as measured and calculated using Method 25 in appendix A to part 60 of this chapter, mg/dscm; and

Q_s = Vent stream flow rate, dscm/min, at a temperature of 20 degrees Celsius (C).

$$E = K_5 (C_{\text{TOC}} - \frac{1}{6} C_{\text{methane}}) Q_s \quad (\text{Eq. 2})$$

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Where:

K_s = Constant, 1.8×10^{-4} (parts per million)⁻¹ (gram-mole per standard cubic meter) (gram-C per gram-mole-hexane) (kilogram per gram) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees C (uses 72g-C/g.mole hexane);

C_{TOC} = Concentration of TOC on a dry basis in ppmv as hexane as measured by Meth-

od 25A in appendix A to part 60 of this chapter;

$C_{methane}$ = Concentration of methane on a dry basis in ppmv as measured by Method 18 in appendix A to part 60 of this chapter. If the concentration of methane is not determined, assume $C_{methane}$ equals zero; and

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

$$\% \text{ reduction} = \frac{E_i - E_o}{E_i} \times 100\% \quad (\text{Eq. 3})$$

Where:

E_i = Mass emission rate of TOC at control device inlet, kg/hr; and

E_o = Mass emission rate of TOC at control device outlet, kg/hr.

(ii) If you elect the 20 parts per million by volume (ppmv) concentration limit, correct the measured TOC concentration for oxygen (O_2) content in the gas stream using Equation 4 of this section as follows:

$$C_{NMTOC, 3\%O_2} = (C_{TOC} - \frac{1}{6} C_{methane}) \left(\frac{17.9\%}{20.9\% - \%O_2} \right) \quad (\text{Eq. 4})$$

Where:

$C_{NMTOC, 3\%O_2}$ = Concentration of nonmethane TOC on a dry basis in ppmv as hexane corrected to 3 percent oxygen.

(5) You are not required to do a TOC performance test if:

(i) You elect to vent emissions to a flare as provided in paragraph (a)(1)(i) of this section (Option 1); or

(ii) You elect the TOC percent reduction or concentration limit in paragraph (a)(1)(ii) of this section (Option 2), and you use a boiler or process heater with a design heat input capacity of 44 MW or greater or a boiler or process heater in which all vent streams are introduced into the flame zone.

(6) Demonstrate initial compliance with each emission limitation that applies to you according to Table 19 of this subpart.

(7) Demonstrate initial compliance with the work practice standard in paragraph (a)(5) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(8) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 15 and 16 of this subpart that applies to you according to the methods specified in Tables 20 and 21 of this subpart.

(2) Demonstrate continuous compliance with the work practice standards in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005]

§ 63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 22 to this subpart that applies to you. If you operate a catalytic reforming unit in which different reactors in the catalytic reforming unit are regenerated in separate regeneration systems, then these emission limitations apply to each separate regeneration system. These emission limitations apply to emissions from catalytic reforming unit process vents associated with the coke burn-off and catalyst rejuvenation operations during coke burn-off and catalyst regeneration. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet a percent reduction standard for hydrogen chloride (HCl) emissions (Option 1); or

(ii) You can elect to meet an HCl concentration limit (Option 2).

(2) Meet each site-specific operating limit in Table 23 of this subpart that applies to you. These operating limits

apply during coke burn-off and catalyst rejuvenation.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in § 63.1572 and Table 24 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in § 63.1571 and the conditions specified in Table 25 of this subpart.

(3) Establish each site-specific operating limit in Table 23 of this subpart that applies to you according to the procedures in Table 25 of this subpart.

(4) Use the equations in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) Correct the measured HCl concentration for oxygen (O₂) content in the gas stream using Equation 1 of this section as follows:

$$C_{\text{HCl}, 3\% \text{O}_2} = \left(\frac{17.9\%}{20.9\% - \% \text{O}_2} \right) C_{\text{HCl}} \quad (\text{Eq. 1})$$

Where:

$C_{\text{HCl}, 3\% \text{O}_2}$ = Concentration of HCl on a dry basis in ppmv corrected to 3 percent oxygen or 1 ppmv, whichever is greater;

C_{HCl} = Concentration of HCl on a dry basis in ppmv, as measured by Method 26A in 40 CFR part 60, appendix A; and

$\% \text{O}_2$ = Oxygen concentration in percent by volume (dry basis).

(ii) If you elect the percent reduction standard, calculate the emission rate of HCl using Equation 2 of this section; then calculate the mass emission reduction from the mass emission rates

using Equation 3 of this section as follows:

$$E_{\text{HCl}} = K_6 C_{\text{HCl}} Q_s \quad (\text{Eq. 2})$$

Where:

E_{HCl} = Emission rate of HCl in the vent stream, grams per hour;

K_6 = Constant, 0.091 (parts per million)⁻¹ (grams HCl per standard cubic meter) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees Celsius (C); and

Q_s = Vent stream flow rate, dscm/min, at a temperature of 20 degrees C.

$$\text{HCl\%reduction} = \frac{E_{\text{HCl},i} - E_{\text{HCl},o}}{E_{\text{HCl},i}} \times 100\% \quad (\text{Eq. 3})$$

Where:

$E_{\text{HCl},i}$ = Mass emission rate of HCl at control device inlet, g/hr; and

$E_{\text{HCl},o}$ = Mass emission rate of HCl at control device outlet, g/hr.

(iii) If you are required to use a colorimetric tube sampling system to demonstrate continuous compliance with the HCl concentration operating limit, calculate the HCl operating limit using Equation 4 of this section as follows:

$$C_{\text{HCl}, \text{ppmvLimit}} = 0.9 C_{\text{HCl}, \text{AveTube}} \left(\frac{C_{\text{HCl}, \text{RegLimit}}}{C_{\text{HCl}, 3\%O_2}} \right) \quad (\text{Eq. 4})$$

Where:

$C_{\text{HCl}, \text{ppmvLimit}}$ = Maximum permissible HCl concentration for the HCl concentration operating limit, ppmv;

$C_{\text{HCl}, \text{AveTube}}$ = Average HCl concentration from the colorimetric tube sampling system, calculated as the arithmetic average of the average HCl concentration measured for each performance test run, ppmv or 1 ppmv, whichever is greater; and

$C_{\text{HCl}, \text{RegLimit}}$ = Maximum permissible outlet HCl concentration for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 10 or 30 ppmv.

(iv) If you are required to use a colorimetric tube sampling system to demonstrate continuous compliance with the percent reduction operating limit, calculate the HCl operating limit using Equation 5 of this section as follows:

$$C_{\text{HCl}, \%Limit} = 0.9 C_{\text{HCl}, \text{AveTube}} \left(\frac{100 - \% \text{HClReduction}_{\text{Limit}}}{100 - \% \text{HClReduction}_{\text{Test}}} \right) \quad (\text{Eq. 5})$$

Where:

$C_{\text{HCl}, \%Limit}$ = Maximum permissible HCl concentration for the percent reduction operating limit, ppmv;

$\% \text{HCl Reduction}_{\text{Limit}}$ = Minimum permissible HCl reduction for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 97 or 92 percent; and

$\% \text{HCl Reduction}_{\text{Test}}$ = Average percent HCl reduction calculated as the arithmetic average HCl reduction calculated using Equation 3 of this section for each performance source test, percent.

(5) Demonstrate initial compliance with each emission limitation that ap-

plies to you according to Table 26 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standard? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 22 and 23 of this subpart that applies to you according to the methods specified in Tables 27 and 28 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6939, Feb. 9, 2005]

§ 63.1568 What are my requirements for HAP emissions from sulfur recovery units?

(a) *What emission limitations and work practice standard must I meet?* You must:

(1) Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in § 60.104 of this chapter, you must meet the emission limitations for NSPS units. If your sulfur recovery unit isn't subject to the NSPS for sulfur oxides, you can choose from the options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet the NSPS requirements (Option 1); or

(ii) You can elect to meet the total reduced sulfur (TRS) emission limitation (Option 2).

(2) Meet each operating limit in Table 30 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in § 63.1572 and Table 31 of this subpart.

(2) Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in § 63.1571 and under the conditions specified in Table 32 of this subpart.

(3) Establish each site-specific operating limit in Table 30 of this subpart that applies to you according to the procedures in Table 32 of this subpart.

(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of this section as follows:

$$C_{adj} = C_{meas} \left[\frac{20.9}{20.9 - \%O_2} \right] \quad (\text{Eq. 1})$$

Where:

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

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

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

20.9 = oxygen concentration in air, percent;

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

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 33 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permit-

ting authority as part of your notification of compliance status.

(7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies to you according to the methods specified in Tables 34 and 35 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by

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complying with the procedures in your operation, maintenance, and monitoring plan.

§ 63.1569 What are my requirements for HAP emissions from bypass lines?

(a) *What work practice standards must I meet?* (1) You must meet each work practice standard in Table 36 of this subpart that applies to you. You can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to install an automated system (Option 1);

(ii) You can elect to use a manual lock system (Option 2);

(iii) You can elect to seal the line (Option 3); or

(iv) You can elect to vent to a control device (Option 4).

(2) As provided in § 63.6(g), we, the EPA, may choose to grant you permission to use an alternative to the work practice standard in paragraph (a)(1) of this section.

(3) You must prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the work practice standards?* You must:

(1) If you elect the option in paragraph (a)(1)(i) of this section, conduct each performance test for a bypass line according to the requirements in § 63.1571 and under the conditions specified in Table 37 of this subpart.

(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies to you according to Table 38 of this subpart.

(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

(4) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in § 63.1574.

(c) *How do I demonstrate continuous compliance with the work practice standards?* You must:

(1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies to you according to the requirements in Table 39 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

GENERAL COMPLIANCE REQUIREMENTS

§ 63.1570 What are my general requirements for complying with this subpart?

(a) You must be in compliance with all of the non-opacity standards in this subpart during the times specified in § 63.6(f)(1).

(b) You must be in compliance with the opacity and visible emission limits in this subpart during the times specified in § 63.6(h)(1).

(c) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in § 63.6(e)(1)(i). During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(d) You must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in § 63.6(e)(3).

(e) During periods of startup, shutdown, and malfunction, you must operate in accordance with your SSMP.

(f) You must report each instance in which you did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. You also must report each instance in which you did not meet the work practice standards in this subpart that apply to you. These instances are deviations from the emission limitations and work practice

standards in this subpart. These deviations must be reported according to the requirements in §63.1575.

(g) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e) and the contents of the SSMP.

§63.1571 How and when do I conduct a performance test or other initial compliance demonstration?

(a) *When must I conduct a performance test?* You must conduct performance tests and report the results by no later than 150 days after the compliance date specified for your source in §63.1563 and according to the provisions in §63.7(a)(2). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a followup Notification of Compliance Status report due no later than 150 days after the test.

(1) For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, you must conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for your source in §63.1563.

(2) For each emission limitation where the averaging period is 30 days, the 30-day period for demonstrating initial compliance begins at 12:00 a.m. on the compliance date that is specified for your source in §63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for your source in §63.1563.

(3) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, you must demonstrate initial compliance with either the proposed emission limitation or the promulgated emission limitation no later than October 8, 2002 or within 180 calendar days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(4) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, and you chose to comply with the proposed emission limitation when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limitation by October 10, 2005, or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(b) *What are the general requirements for performance test and performance evaluations?* You must:

(1) Conduct each performance test according to the requirements in §63.7(e)(1).

(2) Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(3) Conduct each performance evaluation according to the requirements in §63.8(e).

(4) Not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(5) Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5, or 8 of §63.1564, and determining the arithmetic average of the calculated emission rates.

(c) *What procedures must I use for an engineering assessment?* You may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If you use an engineering assessment,

you must document all data, assumptions, and procedures to the satisfaction of the applicable permitting authority. An engineering assessment may include the approaches listed in paragraphs (c)(1) through (c)(4) of this section. Other engineering assessments may be used but are subject to review and approval by the applicable permitting authority.

(1) You may use previous test results provided the tests are representative of current operating practices at the process unit, and provided EPA methods or approved alternatives were used;

(2) You may use bench-scale or pilot-scale test data representative of the process under representative operating conditions;

(3) You may use maximum flow rate, TOC emission rate, organic HAP emission rate, or organic HAP or TOC concentration specified or implied within a permit limit applicable to the process vent; or

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

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

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

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

(d) *Can I adjust the process or control device measured values when establishing an operating limit?* If you do a performance test to demonstrate compliance, you must base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. You may adjust the values measured during the performance test according to the criteria in paragraphs (d)(1) through (3) of this section.

(1) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iii) in §63.1564 (Ni lb/hr), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 1 of this section as follows:

$$E_{cat-Limit} = \frac{13 \text{ g Ni/hr}}{NiEmR1_{st}} \times E_{cat-st} \quad (\text{Eq. 1})$$

Where:

$E_{cat-Limit}$ = Operating limit for equilibrium catalyst Ni concentration, mg/kg;

$NiEmR1_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each performance test run, g Ni/hr; and

E_{cat-st} = Average equilibrium Ni concentration from laboratory test results, mg/kg.

(2) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iv) in §63.1564 (Ni lb/1,000 lb of coke burn-

off), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 2 of this section as follows:

$$\text{Ecat-Limit} = \frac{1.0 \text{ mg/kg coke burn-off}}{\text{NiEmR2}_{\text{st}}} \times \text{Ecat}_{\text{st}} \quad (\text{Eq. 2})$$

Where:

NiEmR2_{st} = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of § 63.1564 for each performance test run, mg/kg coke burn-off.

(3) If you choose to adjust the equilibrium catalyst Ni concentration to the maximum level, you can't adjust any other monitored operating parameter (i.e., gas flow rate, voltage, pressure drop, liquid-to-gas ratio).

(4) Except as specified in paragraph (d)(3) of this section, if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, voltage and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of your permitting authority, that your affected source complies with the applicable emission limit at the operating limit based on adjusted values.

(e) *Can I change my operating limit?* You may change the established operating limit by meeting the requirements in paragraphs (e)(1) through (3) of this section.

(1) You may change your established operating limit for a continuous parameter monitoring system by doing an additional performance test, a performance test in conjunction with an engineering assessment, or an engineering assessment to verify that, at the new operating limit, you are in compliance with the applicable emission limitation.

(2) You must establish a revised operating limit for your continuous param-

eter monitoring system if you make any change in process or operating conditions that could affect control system performance or you change designated conditions after the last performance or compliance tests were done. You can establish the revised operating limit as described in paragraph (e)(1) of this section.

(3) You may change your site-specific opacity operating limit or Ni operating limit only by doing a new performance test.

§ 63.1572 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of this subpart.

(2) If you use a continuous emission monitoring system to meet the NSPS CO or SO₂ limit, you must conduct a performance evaluation of each continuous emission monitoring system according to the requirements in § 63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in § 63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Data must be reduced as specified in § 63.8(g)(2).

(b) You must install, operate, and maintain each continuous opacity monitoring system according to the requirements in paragraphs (b)(1) through (3) of this section.

(1) Each continuous opacity monitoring system must be installed, operated, and maintained according to the

requirements in Table 40 of this subpart.

(2) If you use a continuous opacity monitoring system to meet the NSPS opacity limit, you must conduct a performance evaluation of each continuous opacity monitoring system according to the requirements in § 63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in § 63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(c) You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in paragraphs (c)(1) through (5) of this section.

(1) The owner or operator shall install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately. The owner or operator shall also meet the equipment specifications in Table 41 of this subpart if pH strips or colorimetric tube sampling systems are used.

(2) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).

(3) Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.

(4) Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day. The daily aver-

age must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.

(5) Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.

(d) You must monitor and collect data according to the requirements in paragraphs (d)(1) and (2) of this section.

(1) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(2) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005]

§ 63.1573 What are my monitoring alternatives?

(a) *What are the approved alternatives for measuring gas flow rate?* (1) You may use this alternative to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (i.e., complete combustion units with no additional combustion devices). You may also use this alternative to a continuous parameter monitoring system for the catalytic regenerator atmospheric exhaust gas flow rate for your catalytic reforming unit during the coke burn and rejuvenation cycles if the unit operates as a constant pressure system during these cycles. If you use this alternative, you shall use the same procedure for the

performance test and for monitoring after the performance test. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator. Or, you may determine and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reform-

ing unit regenerator using the appropriate control room instrumentation.

(ii) Install and operate a continuous parameter monitoring system to measure and record the temperature of the gases entering the control device (or exiting the catalyst regenerator if you do not use an add-on control device).

(iii) Calculate and record the hourly average actual exhaust gas flow rate using Equation 1 of this section as follows:

$$Q_{\text{gas}} = (1.12 \text{ scfm/dscfm}) \times (Q_{\text{air}} + Q_{\text{other}}) \times \left(\frac{\text{Temp}_{\text{gas}}}{293^\circ \text{K}} \right) \times \left(\frac{1 \text{ atm}}{P_{\text{vent}}} \right) \quad (\text{Eq. 1})$$

Where:

Q_{gas} = Hourly average actual gas flow rate, acfm;

1.12 = Default correction factor to convert gas flow from dry standard cubic feet per minute (dscfm) to standard cubic feet per minute (scfm);

Q_{air} = Volumetric flow rate of air to regenerator, as determined from the control room instrumentations, dscfm;

Q_{other} = Volumetric flow rate of other gases entering the regenerator as determined from the control room instrumentations, dscfm. (Examples of "other" gases include an oxygen-enriched air stream to catalytic cracking unit regenerators and a nitrogen stream to catalytic reforming unit regenerators.);

Temp_{gas} = Temperature of gas stream in vent measured as near as practical to the control device or opacity monitor, °K. For wet scrubbers, temperature of gas prior to the wet scrubber; and

P_{vent} = Absolute pressure in the vent measured as near as practical to the control device or opacity monitor, as applicable, atm. When used to assess the gas flow rate in the

final atmospheric vent stack, you can assume $P_{\text{vent}} = 1 \text{ atm}$.

(2) You may use this alternative to calculating Q_{r} , the volumetric flow rate of exhaust gas for the catalytic cracking regenerator as required in Equation 1 of § 63.1564, if you have a gas analyzer installed in the catalytic cracking regenerator exhaust vent prior to the addition of air or other gas streams. You may measure upstream or downstream of an electrostatic precipitator, but you shall measure upstream of a carbon monoxide boiler. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator. Or, you can determine and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator using the catalytic cracking unit control room instrumentation.

(ii) Install and operate a continuous gas analyzer to measure and record the concentration of carbon dioxide, carbon monoxide, and oxygen of the catalytic cracking regenerator exhaust.

(iii) Calculate and record the hourly average flow rate using Equation 2 of this section as follows:

$$Q_r = \frac{79 \times Q_{\text{air}} + (100 - \%O_{xy}) \times Q_{\text{oxy}}}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. 2})$$

Where:

Q_r = Volumetric flow rate of exhaust gas from the catalyst regenerator before adding air or gas streams, dscm/min (dscf/min);

79 = Default concentration of nitrogen and argon in dry air, percent by volume (dry basis);

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

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

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

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

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

(b) *What is the approved alternative for monitoring pH or alkalinity levels?* You may use the alternative in paragraph (b)(1) or (2) of this section for a catalytic reforming unit.

(1) You shall measure and record the pH of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst rejuvenation using pH strips as an alternative to a continuous parameter monitoring system. The pH strips must meet the requirements in Table 41 of this subpart.

(2) You shall measure and record the alkalinity of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst rejuvenation using titration as an alternative to a continuous parameter monitoring system.

(c) *Can I use another type of monitoring system?* You may request approval from your permitting authority to use an automated data compression system. An automated data compression

system does not record monitored operating parameter values at a set frequency (e.g., once every hour) but records all values that meet set criteria for variation from previously recorded values. Your request must contain a description of the monitoring system and data recording system, including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all of the criteria in paragraphs (c)(1) through (5) of this section:

(1) The system measures the operating parameter value at least once every hour;

(2) The system records at least 24 values each day during periods of operation;

(3) The system records the date and time when monitors are turned off or on;

(4) The system recognizes unchanging data that may indicate the monitor is not functioning properly, alerts the operator, and records the incident; and

(5) The system computes daily average values of the monitored operating parameter based on recorded data.

(d) *Can I monitor other process or control device operating parameters?* You may request approval to monitor parameters other than those required in this subpart. You must request approval if:

(1) You use a control device other than a thermal incinerator, boiler, process heater, flare, electrostatic precipitator, or wet scrubber;

(2) You use a combustion control device (e.g., incinerator, flare, boiler or process heater with a design heat capacity of at least 44 MW, boiler or process heater where the vent stream is introduced into the flame zone), electrostatic precipitator, or scrubber but want to monitor a parameter other than those specified; or

(3) You wish to use another type of continuous emission monitoring system that provides direct measurement

of a pollutant (i.e., a PM or multi-metals HAP continuous emission monitoring system, a carbonyl sulfide/carbon disulfide continuous emission monitoring system, a TOC continuous emission monitoring system, or HCl continuous emission monitoring system).

(e) *How do I request to monitor alternative parameters?* You must submit a request for review and approval or disapproval to the Administrator. The request must include the information in paragraphs (e)(1) through (5) of this section.

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

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

(3) The frequency and content of monitoring, recording, and reporting, if monitoring and recording are not continuous. You also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(4) Supporting calculations.

(5) Averaging time for the alternative operating parameter.

(f) *How do I apply for alternative monitoring requirements if my catalytic cracking unit is equipped with a wet scrubber and I have approved alternative monitoring requirements under the new source performance standards for petroleum refineries?*

(1) You may request alternative monitoring requirements according to the procedures in this paragraph if you meet each of the conditions in paragraphs (f)(1)(i) through (iii) of this section:

(i) Your fluid catalytic cracking unit regenerator vent is subject to the PM

limit in 40 CFR 60.102(a)(1) and uses a wet scrubber for PM emissions control;

(ii) You have alternative monitoring requirements for the continuous opacity monitoring system requirement in 40 CFR 60.105(a)(1) approved by the Administrator; and

(iii) You are required by this subpart to install, operate, and maintain a continuous opacity monitoring system for the same catalytic cracking unit regenerator vent for which you have approved alternative monitoring requirements.

(2) You can request approval to use an alternative monitoring method prior to submitting your notification of compliance status, in your notification of compliance status, or at any time.

(3) You must submit a copy of the approved alternative monitoring requirements along with a monitoring plan that includes a description of the continuous monitoring system or method, including appropriate operating parameters that will be monitored, test results demonstrating compliance with the opacity limit used to establish an enforceable operating limit(s), and the frequency of measuring and recording to establish continuous compliance. If applicable, you must also include operation and maintenance requirements for the continuous monitoring system.

(4) We will contact you within 30 days of receipt of your application to inform you of approval or of our intent to disapprove your request.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005]

NOTIFICATIONS, REPORTS, AND RECORDS

§63.1574 What notifications must I submit and when?

(a) Except as allowed in paragraphs (a)(1) through (3) of this section, you must submit all of the notifications in §§63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) that apply to you by the dates specified.

(1) You must submit the notification of your intention to construct or reconstruct according to §63.9(b)(5) unless construction or reconstruction had commenced and initial startup had not occurred before April 11, 2002. In this

case, you must submit the notification as soon as practicable before startup but no later than July 10, 2002. This deadline also applies to the application for approval of construction or reconstruction and approval of construction or reconstruction based on State preconstruction review required in §§ 63.5(d)(1)(i) and 63.5(f)(2).

(2) You must submit the notification of intent to conduct a performance test required in § 63.7(b) at least 30 calendar days before the performance test is scheduled to begin (instead of 60 days).

(3) If you are required to conduct a performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, you must submit a notification of compliance status according to § 63.9(h)(2)(ii). You can submit this information in an operating permit application, in an amendment to an operating permit application, in a separate submission, or in any combination. In a State with an approved operating permit program where delegation of authority under section 112(l) of the CAA has not been requested or approved, you must provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted previously, you do not have to provide a separate notification of compliance status. Just refer to the earlier submissions instead of duplicating and resubmitting the previously submitted information.

(i) For each initial compliance demonstration that does not include a performance test, you must submit the Notification of Compliance Status no later than 30 calendar days following completion of the initial compliance demonstration.

(ii) For each initial compliance demonstration that includes a performance test, you must submit the notification of compliance status, including the performance test results, no later than 150 calendar days after the compliance date specified for your affected source in § 63.1563.

(b) As specified in § 63.9(b)(2), if you startup your new affected source before April 11, 2002, you must submit the initial notification no later than August 9, 2002.

(c) If you startup your new or reconstructed affected source on or after April 11, 2002, you must submit the initial notification no later than 120 days after you become subject to this subpart.

(d) You also must include the information in Table 42 of this subpart in your notification of compliance status.

(e) If you request an extension of compliance for an existing catalytic cracking unit as allowed in § 63.1563(c), you must submit a notification to your permitting authority containing the required information by October 13, 2003.

(f) As required by this subpart, you must prepare and implement an operation, maintenance, and monitoring plan for each control system and continuous monitoring system for each affected source. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures you will follow.

(1) You must submit the plan to your permitting authority for review and approval along with your notification of compliance status. While you do not have to include the entire plan in your part 70 or 71 permit, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and approval and comply with the plan until the change is approved.

(2) Each plan must include, at a minimum, the information specified in paragraphs (f)(2)(i) through (xii) of this section.

(i) Process and control device parameters to be monitored for each affected source, along with established operating limits.

(ii) Procedures for monitoring emissions and process and control device operating parameters for each affected source.

(iii) Procedures that you will use to determine the coke burn-rate, the volumetric flow rate (if you use process data rather than direct measurement), and the rate of combustion of liquid or solid fossil fuels if you use an incinerator-waste heat boiler to burn the exhaust gases from a catalyst regenerator.

(iv) Procedures and analytical methods you will use to determine the equilibrium catalyst Ni concentration, the equilibrium catalyst Ni concentration monthly rolling average, and the hourly or hourly average Ni operating value.

(v) Procedures you will use to determine the pH of the water (or scrubbing liquid) exiting a wet scrubber if you use pH strips.

(vi) Procedures you will use to determine the HCl concentration of gases from a catalytic reforming unit when you use a colorimetric tube sampling system, including procedures for correcting for pressure (if applicable to the sampling equipment) and the sampling locations that will be used for compliance monitoring purposes.

(vii) Procedures you will use to determine the gas flow rate for a catalytic cracking unit if you use the alternative procedure based on air flow rate and temperature.

(viii) Monitoring schedule, including when you will monitor and when you will not monitor an affected source (e.g., during the coke burn-off, regeneration process).

(ix) Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system you use to meet an emission limit in this subpart. This plan must include procedures you will use for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.

(x) Maintenance schedule for each monitoring system and control device for each affected source that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.

(xi) If you use a fixed-bed gas-solid adsorption system to control emissions from a catalytic reforming unit, you must implement corrective action procedures if the HCl concentration measured at the selected compliance monitoring sampling location within the bed exceeds the operating limit. These procedures must require, at minimum, repeat measurement and recording of the HCl concentration in the adsorption system exhaust gases and at the selected compliance monitoring sam-

pling location within the bed. If the HCl concentration at the selected compliance monitoring location within the bed is above the operating limit during the repeat measurement while the HCl concentration in the adsorption system exhaust gases remains below the operating limit, the adsorption bed must be replaced as soon as practicable. Your procedures must specify the sampling frequency that will be used to monitor the HCl concentration in the adsorption system exhaust gases subsequent to the repeat measurement and prior to replacement of the sorbent material (but not less frequent than once every 4 hours during coke burn-off). If the HCl concentration of the adsorption system exhaust gases is above the operating limit when measured at any time, the adsorption bed must be replaced within 24 hours or before the next regeneration cycle, whichever is longer.

(xii) Procedures that will be used for purging the catalyst if you do not use a control device to comply with the organic HAP emission limits for catalytic reforming units. These procedures will include, but are not limited to, specification of the minimum catalyst temperature and the minimum cumulative volume of gas per mass of catalyst used for purging prior to uncontrolled releases (i.e., during controlled purging events); the maximum purge gas temperature for uncontrolled purge events; and specification of the monitoring systems that will be used to monitor and record data during each purge event.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6941, Feb. 9, 2005]

§ 63.1575 What reports must I submit and when?

(a) You must submit each report in Table 43 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule, you must submit each report by the date in Table 43 of this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.1563 and ending

on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your affected source in § 63.1563.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.1563.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A) of this chapter, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If there are no deviations from any emission limitation that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, mal-

functioning, out-of-control, repaired, or adjusted.

(d) For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the compliance report must contain the information in paragraphs (c)(1) through (3) of this section and the information in paragraphs (d)(1) through (3) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(e) For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in paragraphs (d)(1) through (3) of this section and the information in paragraphs (e)(1) through (13) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high-level checks.

(3) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting

period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.

(8) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.

(9) An identification of each HAP that was monitored at the affected source.

(10) A brief description of the process units.

(11) The monitoring equipment manufacturer(s) and model number(s).

(12) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.

(13) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.

(f) You also must include the information required in paragraphs (f)(1) through (2) of this section in each compliance report, if applicable.

(1) A copy of any performance test done during the reporting period on any affected unit. The report may be included in the next semiannual report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, you must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.

(2) Any requested change in the applicability of an emission standard (e.g., you want to change from the PM standard to the Ni standard for catalytic cracking units or from the HCl concentration standard to percent reduction for catalytic reforming units) in your periodic report. You must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.

(g) You may submit reports required by other regulations in place of or as part of the compliance report if they contain the required information.

(h) The reporting requirements in paragraphs (h)(1) and (2) of this section apply to startups, shutdowns, and malfunctions:

(1) When actions taken to respond are consistent with the plan, you are not required to report these events in the semiannual compliance report and the reporting requirements in §§ 63.6(e)(3)(iii) and 63.10(d)(5) do not apply.

(2) When actions taken to respond are not consistent with the plan, you must report these events and the response taken in the semiannual compliance

report. In this case, the reporting requirements in §§ 63.6(e)(3)(iv) and 63.10(d)(5) do not apply.

(i) If the applicable permitting authority has approved a period of planned maintenance for your catalytic cracking unit according to the requirements in paragraph (j) of this section, you must include the following information in your compliance report.

(1) In the compliance report due for the 6-month period before the routine planned maintenance is to begin, you must include a full copy of your written request to the applicable permitting authority and written approval received from the applicable permitting authority.

(2) In the compliance report due after the routine planned maintenance is complete, you must include a description of the planned routine maintenance that was performed for the control device during the previous 6-month period, and the total number of hours during those 6 months that the control device did not meet the emission limitations and monitoring requirements as a result of the approved routine planned maintenance.

(j) If you own or operate multiple catalytic cracking units that are served by a single wet scrubber emission control device (e.g., a Venturi scrubber), you may request the applicable permitting authority to approve a period of planned routine maintenance for the control device needed to meet requirements in your operation, maintenance, and monitoring plan. You must present data to the applicable permitting authority demonstrating that the period of planned maintenance results in overall emissions reductions. During this pre-approved time period, the emission control device may be taken out of service while maintenance is performed on the control device and/or one of the process units while the remaining process unit(s) continue to operate. During the period the emission control device is unable to operate, the emission limits, operating limits, and monitoring requirements applicable to the unit that is operating and the wet scrubber emission control device do not apply. The applicable permitting authority may require that you take specified actions to minimize emissions

during the period of planned maintenance.

(1) You must submit a written request to the applicable permitting authority at least 6 months before the planned maintenance is scheduled to begin with a copy to the EPA Regional Administrator.

(2) Your written request must contain the information in paragraphs (j)(2)(i) through (v) of this section.

(i) A description of the planned routine maintenance to be performed during the next 6 months and why it is necessary.

(ii) The date the planned maintenance will begin and end.

(iii) A quantified estimate of the HAP and criteria pollutant emissions that will be emitted during the period of planned maintenance.

(iv) An analysis showing the emissions reductions resulting from the planned maintenance as opposed to delaying the maintenance until the next unit turnaround.

(v) Actions you will take to minimize emissions during the period of planned maintenance.

§ 63.1576 What records must I keep, in what form, and for how long?

(a) You must keep the records specified in paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) The records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in § 63.10(b)(2)(viii).

(b) For each continuous emission monitoring system and continuous opacity monitoring system, you must keep the records required in paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring systems during a

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performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (i.e., superceded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records in §63.6(h) for visible emission observations.

(d) You must keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines) to show continuous compliance with each emission limitation that applies to you.

(e) You must keep a current copy of your operation, maintenance, and monitoring plan onsite and available for inspection. You also must keep records to show continuous compliance with the procedures in your operation, maintenance, and monitoring plan.

(f) You also must keep the records of any changes that affect emission control system performance including, but not limited to, the location at which the vent stream is introduced into the flame zone for a boiler or process heater.

(g) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(h) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(i) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records offsite for the remaining 3 years.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

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OTHER REQUIREMENTS AND INFORMATION

§63.1577 What parts of the General Provisions apply to me?

Table 44 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.1578 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of alternatives to the non-opacity emission limitations and work practice standards in §§63.1564 through 63.1569 under §63.6(g).

(2) Approval of alternative opacity emission limitations in §§63.1564 through 63.1569 under §63.6(h)(9).

(3) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

§63.1579 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in 40 CFR 63.2, the General Provisions of this part (§§63.1 through 63.15), and in this section as listed.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and equipment used for heat recovery.

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

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

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

generative, cyclic, or continuous regeneration process.

Coke burn-off means the coke removed from the surface of the catalytic cracking unit catalyst or the catalytic reforming unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated using Equation 2 in § 63.1564.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the destruction of organic HAP or VOC.

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

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

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

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

Cyclic regeneration reforming means a catalytic reforming process characterized by continual batch regeneration of catalyst in situ in any one of several reactors (e.g., 4 or 5 separate reactors) that can be isolated from and returned to the reforming operation while maintaining continuous reforming process operations (i.e., feedstock continues flowing through the remaining reactors without change in feed rate or product octane).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during start-up, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Emission limitation means any emission limit, opacity limit, operating limit, or visible emission limit.

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

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

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by the source, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species.

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

Incinerator means an enclosed combustion device that is used for destroy-

ing organic compounds, with or without heat recovery. Auxiliary fuel may be used to heat waste gas to combustion temperatures. An incinerator may use a catalytic combustion process where a substance is introduced into an exhaust stream to burn or oxidize contaminants while the substance itself remains intact, or a thermal process which uses elevated temperatures as a primary means to burn or oxidize contaminants.

Internal scrubbing system means a wet scrubbing, wet injection, or caustic injection control device that treats (in-situ) the catalytic reforming unit recirculating coke burn exhaust gases for acid (HCl) control during reforming catalyst regeneration upstream of the atmospheric coke burn vent.

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

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

Oxidation control system means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to sulfur dioxide.

PM means, for the purposes of this subpart, emissions of particulate matter that serve as a surrogate measure of the total emissions of particulate matter and metal HAP contained in the particulate matter, including but not limited to: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium

as measured by Methods 5B or 5F in appendix A to part 60 of this chapter or by an approved alternative method.

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

Process vent means, for the purposes of this subpart, a gas stream that is continuously or periodically discharged during normal operation of a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit, including gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device line prior to control or discharge to the atmosphere.

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

Reduction control system means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to hydrogen sulfide.

Responsible official means responsible official as defined in 40 CFR 70.2.

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

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

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

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

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 1 TO SUBPART UUU OF PART 63—METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

As stated in §63.1564(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	You shall meet the following emission limits for each catalyst regenerator vent . . .
1. Subject to new source performance standard (NSPS) for PM in 40 CFR 60.102.	PM emissions must not exceed 1.0 kilogram (kg) per 1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or in supplemental liquid or solid fossil fuel, the incremental rate of PM emissions must not exceed 43.0 grams per Gigajoule (g/GJ) or 0.10 pounds per million British thermal units (lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 8-minute average opacity reading in any 1-hour period.

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For each new or existing catalytic cracking unit . . .	You shall meet the following emission limits for each catalyst regenerator vent . . .
2. Option 1: NSPS requirements not subject to the NSPS for PM in 40 CFR 60.102.	PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 5-minute average opacity reading in any 1-hour period.
3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102.	PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lbs) of coke burn-off in the catalyst regenerator.
4. Option 3: Ni lb/hr not subject to the NSPS for PM in 40 CFR 60.102.	Nickel (Ni) emissions must not exceed 13,000 milligrams per hour (mg/hr) (0.029 lb/hr).
5. Option 4: Ni Lb/1,000 lbs of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102.	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 2 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

As stated in §63.1564(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
1. Subject to the NSPS for PM in 40 CFR 60.102.	Continuous opacity monitoring system.	Not applicable	Not applicable.
2. Option 1: NSPS requirements not subject to the NSPS for PM in 40 CFR 60.102.	Continuous opacity monitoring system.	Not applicable	Not applicable.
3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Continuous opacity monitoring system.	Electrostatic precipitator	Maintain the hourly average opacity of emissions from your catalyst regenerator vent no higher than the site-specific opacity limit established during the performance test.
	b. Continuous parameter monitoring systems.	Electrostatic precipitator	Maintain the daily average gas flow rate no higher than the limit established in the performance test; and maintain the daily average voltage and secondary current (or total power input) above the limit established in the performance test.
	c. Continuous parameter monitoring systems.	Wet scrubber	Maintain the daily average pressure drop above the limit established in the performance test (not applicable to a wet scrubber of the non-venturi jet-ejector design); and maintain the daily average liquid-to-gas ratio above the limit established in the performance test.
4. Option 3: Ni lb/hr not subject to the NSPS for PM in 40 CFR 60.102.	a. Continuous opacity monitoring system.	Electrostatic precipitator	Maintain the daily average Ni operating value no higher than the limit established during the performance test.

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For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
5. Option 4: Ni lb/1,000 lbs of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102.	b. Continuous parameter monitoring systems.	i. Electrostatic precipitator	Maintain the daily average gas flow rate no higher than the limit established during the performance test; maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; and maintain the daily average voltage and secondary current (or total power input) above the established during the performance test.
		ii. Wet scrubber	Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design); and maintain the daily average liquid-to-gas ratio above the limit established during the performance test.
	a. Continuous opacity monitoring system	Electrostatic precipitator	Maintain the daily average Ni operating value no higher than the Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems.	i. Electrostatic precipitator	Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; and maintain the daily average voltage and secondary current for total power input) above the limit established during the performance test.
		ii. Wet scrubber	Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design); and maintain the daily average liquid-to-gas ratio above the limit established during the performance test.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 3 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

As stated in §63.1564(b)(1), you shall meet each requirement in the following table that applies to you.

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For each new or existing catalytic cracking unit . . .	If your catalytic cracking unit is . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
1. Subject to the NSPS for PM in 40 CFR 60.102.	Any size	Electrostatic precipitator or wet scrubber or no control device.	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.
2. Option 1: NSPS limits not subject to the NSPS for PM in 40 CFR 60.102.	Any size	Electrostatic precipitator or wet scrubber or no control device.	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.
3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Over 20,000 barrels per day fresh feed capacity.	Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.
	b. Up to 20,000 barrels per day fresh feed capacity.	Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the gas flow rate entering or exiting the control device ¹ and the voltage and secondary current (or total power input) to the control device.
	c. Any size	i. Wet scrubber	(1) Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, gas flow rate entering or exiting the control device ¹ , and total liquid (or scrubbing liquor) flow rate to the control device. (2) If you use a wet scrubber of the non-venturi jet-ejector design, you're not required to install and operate a continuous parameter monitoring system for pressure drop.
	d. Any size	No electrostatic precipitator or wet scrubber.	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.
4. Option 3: Ni lb/hr not subject to the NSPS for PM in 40 CFR 60.102.	a. Over 20,000 barrels per day fresh feed capacity.	Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device ¹ .

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For each new or existing catalytic cracking unit . . .	If your catalytic cracking unit is . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
5. Option 4: Ni lb/1,000 lbs of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102.	b. Up to 20,000 barrels per day fresh feed capacity.	Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device ¹ ; or continuous parameter monitoring systems to measure and record the gas flow rate entering or exiting the control device ¹ and the voltage and secondary current (or total power input) to the control device.
	c. Any size	Wet scrubber	(1) Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, gas flow rate entering or exiting the control device ¹ , and total liquid (or scrubbing liquor) flow rate to the control device. (2) If you use a wet scrubber of the non-venturi jet-ejector design, you're not required to install and operate a continuous parameter monitoring system for pressure drop.
	d. Any size	No electrostatic precipitator or wet scrubber.	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate ¹ .
	a. Over 20,000 barrels per day fresh feed capacity.	Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device ¹ .
	b. Up to 20,000 barrels per day fresh feed capacity.	Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device ¹ ; or continuous parameter monitoring systems to measure and record the gas flow rate entering or exiting the control device ¹ and the voltage and secondary current (or total power input) to the control device.

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For each new or existing catalytic cracking unit . . .	If your catalytic cracking unit is . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
	c. Any size	Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, gas flow rate entering or exiting the control device ¹ , and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Any size	No electrostatic precipitator or wet scrubber.	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate ¹ .

¹ If applicable, you can use the alternative in § 63.1573(a)(1) instead of a continuous parameter monitoring system for gas flow rate.

[70 FR 6942, Feb. 9, 2005]

TABLE 4 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS NOT SUBJECT TO THE NEW SOURCE PERFORMANCE STANDARD (NSPS) FOR PARTICULATE MATTER (PM)

As stated in §63.1564(b)(2), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must . . .	Using . . .	According to these requirements . . .
1. If you elect Option 1 in item 2 of Table 1, Option 2 in item 3 of Table 1, Option 3 in item 4 of Table 1, or Option 4 in item 5 of Table 1 of this subpart.	<p>a. Select sampling port's location and the number of traverse ports.</p> <p>b. Determine velocity and volumetric flow rate.</p> <p>c. Conduct gas molecular weight analysis.</p> <p>d. Measure moisture content of the stack gas.</p> <p>e. If you use an electro-static precipitator, record the total number of fields in the control system and how many operated during the applicable performance test.</p> <p>f. If you use a wet scrubber, record the total amount (rate) of water (or scrubbing liquid) and the amount (rate) of make-up liquid to the scrubber during each test run.</p>	<p>Method 1 or 1A in appendix A to part 60 of this chapter.</p> <p>Method 2, 2A, 2C, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable.</p> <p>Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable.</p> <p>Method 4 in appendix A to part 60 of this chapter.</p>	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.

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For each new or existing catalytic cracking unit catalyst regenerator vent	You must . . .	Using . . .	According to these requirements . . .
2. Option 1: Elect NSPS	<p>a. Measure PM emissions.</p> <p>b. Compute PM emission rate (lbs/1,000 lbs) of coke burn-off.</p> <p>c. Measure opacity of emissions.</p>	<p>Method 5B or 5F (40 CFR part 60, appendix A) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5B (40 CFR part 60, appendix A) to determine PM emissions and associated moisture content for unit with wet scrubber.</p> <p>Equations 1, 2, and 3 of §63.1564 (if applicable).</p> <p>Continuous opacity monitoring system.</p>	<p>You must maintain a sampling rate of at least 0.15 dry standard cubic meters per minute (dscm/min) (0.53 dry standard cubic feet per minute (dscf/min).</p> <p>You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5B or 5F performance test and reduce the data to 6-minute averages.</p>
3. Option 2: PM limit	<p>a. Measure PM emissions.</p> <p>b. Compute coke burn-off rate and PM emission rate.</p> <p>c. Establish your site-specific opacity operating limit if you use a continuous opacity monitoring system.</p>	<p>See item 2. of this table.</p> <p>Equations 1 and 2 of §63.1564.</p> <p>Data from the continuous opacity monitoring system.</p>	<p>See item 2. of this table.</p> <p>You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5B or 5F performance test and reduce the data to 6-minute averages; determine and record the hourly average opacity from all the 6-minute averages; and compute the site-specific limit using Equation 4 of §63.1564.</p>
4. Option 3: Ni lb/hr	<p>a. Measure concentration of Ni and total metal HAP.</p> <p>b. Compute Ni emission rate (lb/hr).</p> <p>c. Determine the equilibrium catalyst Ni concentration.</p> <p>d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit.</p>	<p>Method 29 (40 CFR part 60, appendix A).</p> <p>Equation 5 of §63.1564.</p> <p>XRF procedure in appendix A to this subpart¹; or EPA Method 6010B or 6020 or EPA Method 7520 or 7521 in SW-846²; or an alternative to the SW-846 method satisfactory to the Administrator.</p> <p>i. Equations 6 and 7 of §63.1564 using data from continuous opacity monitoring system, gas flow rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test.</p>	<p>You must obtain 1 sample for each of the 3 runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of §63.1571.</p> <p>(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the hourly average opacity from all the 6-minute averages.</p> <p>(2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate from all the readings.</p>
5. Option 4: Ni lbs/1,000 lbs of coke burn-off.	a. Measure concentration of Ni and total HAP.	Method 29 (40 CFR part 60, appendix A).	

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For each new or existing catalytic cracking unit catalyst regenerator vent	You must . . .	Using . . .	According to these requirements . . .
6. If you elect Option 2 in Entry 3 in Table 1, Option 3 in Entry 4 in Table 1, or Option 4 in Entry 5 in Table 1 of this subpart and you use continuous parameter monitoring systems.	b. Compute Ni emission rate (lb/1,000 lbs of coke burn-off).	Equations 1 and 8 of § 63.1564.	You must obtain 1 sample for each of the 3 runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of § 63.1571.
	c. Determine the equilibrium catalyst Ni concentration.	See item 4.c. of this table.	
	d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit.	i. Equations 9 and 10 of § 63.1564 with data from continuous opacity monitoring system, coke burn-off rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test.	(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the hourly average opacity from all the 6-minute averages. (2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow rate as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate from all the readings.
	e. Record the catalyst addition rate for each test and schedule for the 10- day period prior to the test.		
	a. Establish each operating limit in Table 2 of this subpart that applies to you.	Data from the continuous parameter monitoring systems and applicable performance test methods.	
	b. Electrostatic precipitator or wet scrubber: gas flow rate.	Data from the continuous parameter monitoring systems and applicable performance test methods.	You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the maximum hourly average gas flow rate from all the readings.
	c. Electrostatic precipitator: voltage and secondary current (or total power input).	Data from the continuous parameter monitoring systems and applicable performance test methods.	You must collect voltage and secondary current (or total power input) monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the minimum hourly average voltage and secondary current (or total power input) from all the readings.
	d. Electrostatic precipitator or wet scrubber: equilibrium catalyst Ni concentration.	Results of analysis for equilibrium catalyst Ni concentration.	You must determine and record the average equilibrium catalyst Ni concentration for the 3 runs based on the laboratory results. You may adjust the value using Equation 1 or 2 of § 63.1571 as applicable.

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must: . . .	Using . . .	According to these requirements . . .
	e. Wet scrubber: pressure drop (not applicable to non-venturi scrubber or jet ejector design).	Data from the continuous parameter monitoring systems and applicable performance test methods.	You must collect pressure drop monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the minimum hourly average pressure drop from all the readings.
	f. Wet scrubber: liquid-to-gas ratio.	Data from the continuous parameter monitoring systems and applicable performance test methods.	You must collect gas flow rate and total water (or scrubbing liquid) flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate from all the readings; and determine and record the minimum liquid-to-gas ratio.
	g. Alternative procedure for gas flow rate.	Data from the continuous parameter monitoring systems and applicable performance test methods.	You must collect air flow rate monitoring data or determine the air flow rate using control room instrumentation every 15 minutes during the entire period of the initial performance test; determine and record the hourly average rate of all the readings; and determine and record the maximum gas flow rate using Equation 1 of § 63.1573.

¹Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure).

²EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, and EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B-108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6944, Feb. 9, 2005]

TABLE 5 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

As stated in § 63.1564(b)(5), you shall meet each requirement in the following table that applies to you.

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For each new and existing catalytic cracking unit catalyst regenerator vent . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for PM in 40 CFR 60.102.	PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 grams per Gigajoule (g/GJ) or 0.10 pounds per million British thermal units (lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. If applicable, you have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM rate is less than or equal to 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel. As part of the Notification of Compliance Status, you must certify that your vent meets the PM emission limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance test to demonstrate initial compliance with the NSPS and the average hourly opacity is no more than 30 percent. Except: One 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the opacity limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you certify that your continuous opacity monitoring system meets the requirements in § 63.1572. You are not required to do a performance evaluation to demonstrate initial compliance.
2. Option 1: Elect NSPS not subject to the NSPS for PM.	PM emission must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	The average PM emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or 5B (for a unit with a wet scrubber), over the period of the initial performance test, is no higher than 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. The PM emission rate is calculated using Equations 1 and 2 of § 63.1564. If applicable, the average PM emission rate, measured using EPA Method 5B emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or Method 5B (for a unit with a wet scrubber) over the period of the initial performance test, is no higher than 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel. The PM emission rate is calculated using Equation 3 of § 63.1564; no more than one 6-minute average measured by the continuous opacity monitoring system exceeds 30 percent opacity in any 1-hour period over the period of the performance test; and your performance evaluation shows the continuous opacity monitoring system meets the applicable requirements in § 63.1572.

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For each new and existing catalytic cracking unit catalyst regenerator vent . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
3. Option 2: Not subject to the NSPS for PM.	PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator.	The average PM emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or Method 5B (for a unit with a wet scrubber), over the period of the initial performance test, is less than or equal to 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. The PM emission rate is calculated using Equations 1 and 2 of § 63.1564; and if you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.
4. Option 3: not subject to the NSPS for PM.	Nickel (Ni) emissions from your catalyst regenerator vent must not exceed 13,000 mg/hr (0.029 lb/hr).	The average Ni emission rate, measured using Method 29 over the period of the initial performance test, is not more than 13,000 mg/hr (0.029 lb/hr). The Ni emission rate is calculated using Equation 5 of § 63.1564; and if you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.
5. Option 4: Ni lb/1,000 lbs of coke burn-off not subject to the NSPS for PM.	Ni emissions from your catalyst regenerator vent must not exceed 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator.	The average Ni emission rate, measured using Method 29 over the period of the initial performance test, is not more than 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator. The Ni emission rate is calculated using Equation 8 of § 63.1564; and if you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in § 63.1572.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6946, Feb. 9, 2005]

TABLE 6 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for PM in 40 CFR 60.102.	a. PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.	i. Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in § 63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 1.0 kg/1,000 kg (1.0 lb/1,000 lbs) of coke burn-off; if applicable, determining and recording each day the rate of combustion of liquid or solid fossil fuels (liters/hour or kilograms/hour) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler; if applicable, maintaining the PM rate incinerator below 43 g/GJ (0.10 lb/million Btu) of heat input attributable to the solid or liquid fossil fuel; collecting the continuous opacity monitoring data for each catalyst regenerator vent according to § 63.1572; and maintaining each 6-minute average at or below 30 percent except that one 6-minute average during a 1-hour period can exceed 30 percent.

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For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
2. Option 1: Elect NSPS not subject to the NSPS for PM in 40 CFR 60.102.	See item 1.a. of this table	See item 1.a.i. of this table.
3. Option 2: PM limit not subject to the NSPS for PM.	PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator.	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) and the hours of operation for each catalyst regenerator by Equation 1 of § 63.1564 (you can use process data to determine the volumetric flow rate); and maintaining the PM emission rate below 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off.
4. Option 3: Ni lb/hr not subject to the NSPS for PM.	Ni emissions must not exceed 13,000 mg/hr (0.029 lb/hr).	Maintaining Ni emission rate below 13,000 mg/hr (0.029 lb/hr).
5. Option 4: Ni lb/1,000 lbs of coke burn-off not subject to the NSPS for PM.	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator.	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) and the hours of operation for each catalyst regenerator by Equation 1 of § 63.1564 (you can use process data to determine the volumetric flow rate); and maintaining Ni emission rate below 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 7 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 7 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

[As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.]

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS for PM in 40 CFR 60.102.	Continuous opacity monitoring system.	Not applicable.	Complying with Table 6 of this subpart.
2. Option 1: Elect NSPS not subject to the NSPS for PM in 40 CFR 60.102.	Continuous opacity monitoring system.	Not applicable.	Complying with Table 6 of this subpart.
3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102.	a. Continuous opacity monitoring system.	The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test.	Collecting the hourly average continuous opacity monitoring system data according to § 63.1572; and maintaining the hourly average opacity at or below the site-specific limit.
	b. Continuous parameter monitoring systems—electrostatic precipitator.	i. The daily average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test.	Collecting the hourly and daily average gas flow rate monitoring data according to § 63.1572 ¹ ; and maintaining the daily average gas flow rate at or below the limit established during the performance test.

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TABLE 7 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

[As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.]

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
4. Option 3: Ni lb/hr not subject to the NSPS for PM in 40 CFR 60.102.	c. Continuous parameter monitoring systems—wet scrubber.	ii. The daily average voltage and secondary current (or total power input) to the control device must not fall below the operating limit established during the performance test.	Collecting the hourly and daily average voltage and secondary current (or total power input) monitoring data according to § 63.1572; and maintaining the daily average voltage and secondary current (or total power input) at or above the limit established during the performance test.
		i. The daily average pressure drop across the scrubber must not fall below the operating limit established during the performance test.	Collecting the hourly and daily average pressure drop monitoring data according to § 63.1572; and maintaining the daily average pressure drop above the limit established during the performance test.
		ii. The daily average liquid-to-gas ratio must not fall below the operating limit established during the performance test.	Collecting the hourly average gas flow rate and water (or scrubbing liquid) flow rate monitoring data according to § 63.1572 ¹ ; determining and recording the hourly average liquid-to-gas ratio; determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
	a. Continuous opacity monitoring system.	The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test.	Collecting the hourly average continuous opacity monitoring system data according to § 63.1572; determining and recording equilibrium catalyst Ni concentration at least once a week ² ; collecting the hourly average gas flow rate monitoring data according to § 63.1572 ¹ ; determining and recording the hourly average Ni operating value using Equation 11 of § 63.1564; determining and recording the daily average Ni operating value; and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems—electrostatic precipitator.	i. The daily average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test.	See item 3.b.i. of this table.

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TABLE 7 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

[As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.]

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
5. Option 4: Ni lb/ton of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102.	c. Continuous parameter monitoring systems—wetscrubber.	<p>ii. The daily average voltage and secondary current (or total power input) must not fall below the level established in the performance test.</p> <p>iii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test.</p>	<p>See item 3.b.ii. of this table.</p> <p>Determining and recording the equilibrium catalyst Ni concentration at least once a week²; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.</p> <p>See item 3.c.i. of this table.</p>
	a. Continuous opacity monitoring system.	<p>i. The daily average pressure drop must not fall below the operating limit established in the performance test.</p> <p>ii. The daily average liquid-to-gas ratio must not fall below the operating limit established during the performance test.</p> <p>iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test.</p> <p>The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test.</p>	<p>See item 3.c.ii. of this table.</p> <p>Determining and recording the equilibrium catalyst Ni concentration at least once a week²; determining and recording the monthly rolling average of equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.</p> <p>Collecting the hourly average continuous opacity monitoring system data according to § 63.1572; collecting the hourly average gas flow rate monitoring data according to § 63.1572¹; determining and recording equilibrium catalyst Ni concentration at least once a week²; determining and recording the hourly average Ni operating value using Equation 12 of § 63.1564; determining and recording the daily average Ni operating value; and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.</p>

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TABLE 7 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS—Continued

(As stated in § 63.1564(c)(1), you shall meet each requirement in the following table that applies to you.)

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
	b. Continuous parameter monitoring systems—electrostatic precipitator.	i. The daily average gas flow rate to the control device must not exceed the level established in the performance test.	See item 3.b.i. of this table.
		ii. The daily average voltage and secondary current (or total power input) must not fall below the level established in the performance test.	See item 3.b.ii. of this table.
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	See item 4.b.iii. of this table.
	c. Continuous parameter monitoring systems—wet scrubber.	i. The daily average pressure drop must not fall below the operating limit established in the performance test.	See item 3.c.i. of this table.
		ii. The daily average liquid-to-gas ratio must not fall below the operating limit established during the performance test.	See item 3.c.ii. of this table.
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test.	See item 4.c.iii. of this table.

¹ If applicable, you can use the alternative in § 63.1573(a)(1) for gas flow rate instead of a continuous parameter monitoring system if you used the alternative method in the initial performance test.

² The equilibrium catalyst Ni concentration must be measured by the procedure, Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to this subpart; or by EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, or EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration; or by an alternative to EPA Method 6010B, 6020, 7520, or 7521 satisfactory to the Administrator. The EPA Methods 6010B, 6020, 7520, and 7521 are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B-108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. These methods are also available at <http://www.epa.gov/epaoswer/hazwaste/test/main.htm>.

[70 FR 6948, Feb. 9, 2005]

TABLE 8 TO SUBPART UUU OF PART 63—ORGANIC HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

As stated in § 63.1565(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	You shall meet the following emission limit for each catalyst regenerator vent . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103.	CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 parts per million volume (ppmv) (dry basis).
2. Not subject to the NSPS for CO in 40 CFR 60.103 . . .	<p>a. CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).</p> <p>b. If you use a flare to meet the CO limit, the flare must meet the requirements for control devices in § 63.11(b): visible emissions must not exceed a total of 5 minutes during any 2 consecutive hours.</p>

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 9 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

As stated in §63.1565(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103.	Continuous emission monitoring system.	Not applicable	Not applicable.
2. Not subject to the NSPS for CO in 40 CFR 60.103.	a. Continuous emission monitoring system. b. Continuous parameter monitoring systems.	Not applicable i. Thermal incinerator ii. Boiler or process heater with a design heat input capacity under 44 MW or a boiler or process heater in which all vent streams are not introduced into the flame zone. iii. Flare	Not applicable. Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test. Maintain the daily average combustion zone temperature above the limit established in the performance test. The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 10 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

As stated in §63.1565(b)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain this type of continuous monitoring system . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103.	Not applicable	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.
2. Not subject to the NSPS for CO in 40 CFR 60.103.	a. Thermal incinerator b. Process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone.	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature and oxygen content (percent, dry basis) in the incinerator vent stream. Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature.

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For each new or existing catalytic cracking unit . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain this type of continuous monitoring system . . .
	c. Flare	Monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame.
	d. No control device	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 11 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS NOT SUBJECT TO NEW SOURCE PERFORMANCE STANDARD (NSPS) FOR CARBON MONOXIDE (CO)

As stated in §63.1565(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For . . .	You must . . .	Using . . .	According to these requirements . . .
1. Each new or existing catalytic cracking unit catalyst regenerator vent.	a. Select sampling port's location and the number of transverse ports.	Method 1 or 1A in appendix A to part 60 of this chapter.	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable.	
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable.	
	d. Measure moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.	
2. For each new or existing catalytic cracking unit catalyst regenerator vent if you use a continuous emission monitoring system.	Measure CO emissions	Data from your continuous emission monitoring system.	Collect CO monitoring data for each vent for 24 consecutive operating hours; and reduce the continuous emission monitoring data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
3. Each catalytic cracking unit catalyst regenerator vent if you use continuous parameter monitoring systems.	a. Measure the CO concentration (dry basis) of emissions exiting the control device.	Method 10, 10A, or 10B in appendix A to part 60 of this chapter, as applicable.	Collect temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.
	b. Establish each operating limit in Table 9 of this subpart that applies to you.	Data from the continuous parameter monitoring systems.	
	c. Thermal incinerator combustion zone temperature.	Data from the continuous parameter monitoring systems.	

For . . .	You must . . .	Using . . .	According to these requirements . . .
	d. Thermal incinerator: oxygen, content (percent, dry basis) in the incinerator vent stream.	Data from the continuous parameter monitoring systems.	Collect oxygen concentration (percent, dry basis) monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average percent excess oxygen concentration from all the readings.
	e. If you use a process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone, establish operating limit for combustion zone temperature.	Data from the continuous parameter monitoring systems.	Collect the temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.
	f. If you use a flare, conduct visible emission observations.	Method 22 (40 CFR part 60, appendix A).	Maintain a 2-hour observation period; and record the presence of a flame at the pilot light over the full period of the test
	g. If you use a flare, determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity.	40 CFR 60.11(b)(6)through(8).	

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 12 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH ORGANIC HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

As stated in §63.1565(b)(4), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103.	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured CO emissions are less than or equal to 500 ppm (dry basis). As part of the Notification of Compliance Status, you must certify that your vent meets the CO limit. You are not required to conduct another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to conduct another performance evaluation to demonstrate initial compliance.
2. Not subject to the NSPS for CO in 40 CFR 60.103.	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	1. If you use a continuous parameter monitoring system, the average CO emissions measured by Method 10 over the period of the initial performance test are less than or equal to 500 ppmv (dry basis).

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For each new and existing catalytic cracking unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
	b. If you use a flare, visible emissions must not exceed a total of 5 minutes during any 2 operating hours.	<p>ii. If you use a continuous emission monitoring system, the hourly average CO emissions over the 24-hour period for the initial performance test are not more than 500 ppmv (dry basis); and your performance evaluation shows your continuous emission monitoring system meets the applicable requirements in § 63.1572.</p> <p>Visible emissions, measured by Method 22 during the 2-hour observation period during the initial performance test, are no higher than 5 minutes.</p>

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 13 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH ORGANIC HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

As stated in § 63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	If you must . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103.	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system.	Collecting the hourly average CO monitoring data according to § 63.1572; and maintaining the hourly average CO concentration at or below 500 ppmv (dry basis).
2. Not subject to the NSPS for CO in 40 CFR 60.103.	<p>i. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).</p> <p>ii. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).</p> <p>iii. Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour period.</p>	<p>Continuous emission monitoring system.</p> <p>Continuous parameter monitoring system.</p> <p>Control device-flare</p>	<p>Same as above.</p> <p>Maintaining the hourly average CO concentration below 500 ppmv (dry basis).</p> <p>Maintaining visible emissions below a total of 5 minutes during any 2-hour operating period.</p>

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 14 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

As stated in § 63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS for carbon monoxide (CO) in 40 CFR 60.103.	Continuous emission monitoring system.	Not applicable	Complying with Table 13 of this subpart.
2. Not subject to the NSPS for CO in 40 CFR 60.103.	a. Continuous emission monitoring system.	Not applicable	Complying with Table 13 of this subpart.

For each new existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
	b. Continuous parameter monitoring systems—thermal incinerator.	i. The daily average combustion zone temperature must not fall below the level established during the performance test. ii. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test.	Collecting the hourly and daily average temperature monitoring data according to § 63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test. Collecting the hourly and daily average oxygen concentration monitoring data according to § 63.1572; and maintaining the daily average oxygen concentration above the limit established during the performance test.
	c. Continuous parameter monitoring systems—boiler or process heater with a design heat input capacity under 44 MW or boiler or process heater in which all vent streams are not introduced into the flame zone.	The daily combustion zone temperature must not fall below the level established in the performance test.	Collecting the average hourly and daily temperature monitoring data according to § 63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
	d. Continuous parameter monitoring system—flare.	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.	Collecting the flare monitoring data according to § 63.1572; and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

TABLE 15 TO SUBPART UUU OF PART 63—ORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

As stated in § 63.1566(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	You shall meet this emission limit during initial catalyst depressuring and catalyst purging operations . . .
1. Option 1	Vent emissions to a flare that meets the requirements for control devices in § 63.11(b). Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour operating period.
2. Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent. If you vent emissions to a boiler or process heater to comply with the percent reduction or concentration emission limitation, the vent stream must be introduced into the flame zone, or any other location that will achieve the percent reduction or concentration standard.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6951, Feb. 9, 2005]

TABLE 16 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

As stated in § 63.1566(a)(2), you shall meet each operating limit in the following table that applies to you.

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For each new or existing catalytic reforming unit . . .	For this type of control device . . .	You shall meet this operating limit during initial catalyst depressuring and purging operations. . .
1. Option 1: vent to flare	Flare that meets the requirements for control devices in § 63.11(b).	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.
2. Option 2: Percent reduction or concentration limit.	a. Thermal incinerator, boiler or process heater with a design heat input capacity under 44 MW, or boiler or process heater in which all vent streams are not introduced into the flame zone. b. No control device	The daily average combustion zone temperature must not fall below the limit established during the performance test. Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum catalyst purging conditions that must be met prior to allowing uncontrolled purge releases.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6951, Feb. 9, 2005]

TABLE 17 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

As stated in § 63.1566(b)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	If you use this type of control device . . .	You shall install and operate this type of continuous monitoring system . . .
1. Option 1: vent to a flare	Flare that meets the requirements for control devices in § 63.11(b).	Monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame.
2. Option 2: percent reduction or concentration limit.	Thermal incinerator, process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into the flame zone.	Continuous parameter monitoring systems to measure and record the combustion zone temperature.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6952, Feb. 9, 2005]

TABLE 18 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

As stated in § 63.1566(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic reforming unit . . .	You must . . .	Using . . .	According to these requirements . . .
1. Option 1: Vent to a flare	a. Conduct visible emission observations. b. Determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity.	Method 22 (40 CFR part 60, appendix A). Not applicable.	2-hour observation period. Record the presence of a flame at the pilot light over the full period of the test. 40 CFR 63.11(b)(8) through (8).
2. Option 2: Percent reduction or concentration limit.	a. Select sampling site b. Measure gas volumetric flow rate.	Method 1 or 1A (40 CFR part 60, appendix A). No traverse site selection method is needed for vents smaller than 0.10 meter in diameter. Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable.	Sampling sites must be located at the inlet (if you elect the emission reduction standard) and outlet of the control device and prior to any releases to the atmosphere.

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For each new or existing catalytic reforming unit . . .	You must . . .	Using . . .	According to these requirements . . .
	c. Measure TOC concentration (for percent reduction standard).	Method 25 (40 part 60, appendix A) to measure non-methane TOC concentration (in carbon equivalents) at inlet and outlet of the control device. If the non-methane TOC outlet concentration is expected to be less than 50 ppm (as carbon), you can use Method 25A to measure TOC concentration (as hexane) at the inlet and the outlet of the control device. If you use Method 25A, you may use Method 18 (40 CFR part 60, appendix A) to measure the methane concentration to determine the nonmethane TOC concentration.	Take either an integrated sample or four grab samples during each run. If you use a grab sampling technique, take the samples at approximately equal intervals in time, such as 15-minute intervals during the run.
	d. Calculate TOC or non-methane TOC emission rate and mass emission reduction.	Calculate emission rate by Equation 1 of § 63.1566 (if you use Method 25) or Equation 2 of § 63.1566 (if you use Method 25A). Calculate mass emission reduction by Equation 3 of § 63.1566.
	e. For concentration standard, measure TOC concentration. (Optional: Measure methane concentration.)	Method 25A (40 CFR part 60, appendix A) to measure TOC concentration (as hexane) at the outlet of the control device. You may elect to use Method 18 (40 CFR part 60, appendix A) to measure the methane concentration.	
	f. Determine oxygen content in the gas stream at the outlet of the control device.	Method 3A or 3B (40 CFR part 60, appendix A), as applicable.	
	g. Calculate the TOC or non-methane TOC concentration corrected for oxygen content (for concentration standard).	Equation 4 of § 63.1566.	
	h. Establish each operating limit in Table 16 of this subpart that applies to you for a thermal incinerator, or process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into flame zone.	Data from the continuous parameter monitoring systems.	Collect the temperature monitoring data every 15 minutes during the entire period of the initial TOC performance test. Determine and record the minimum hourly average combustion zone temperature.
	i. If you do not use a control device, document the purging conditions used prior to testing following the minimum requirements in the operation, maintenance, and monitoring plan.	Data from monitoring systems as identified in the operation, maintenance, and monitoring plan.	Procedures in the operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6952, Feb. 9, 2005]

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TABLE 19 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH ORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

As stated in §63.1566(b)(7), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
Option 1	Visible emissions from a flare must not exceed a total of 5 minutes during any 2 consecutive hours.	Visible emissions, measured using Method 22 over the 2-hour observation period of the performance test, do not exceed a total of 5 minutes.
Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent.	The mass emission reduction of nonmethane TOC measured by Method 25 over the period of the performance test is at least 98 percent by weight as calculated using Equations 1 and 3 of §63.1566; or the mass emission reduction of TOC measured by Method 25A (or nonmethane TOC measured by Methods 25A and 18) over the period of the performance test is at least 98 percent by weight as calculated using Equations 2 and 3 of §63.1566; or the TOC concentration measured by Method 25A (or the nonmethane TOC concentration measured by Methods 25A and 18) over the period of the performance test does not exceed 20 ppmv (dry basis as hexane) corrected to 3 percent oxygen as calculated using Equation 4 of §63.1566.

[70 FR 6953, Feb. 9, 2005]

TABLE 20 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH ORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	For this emission limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by . . .
1. Option 1	Vent emissions from your process vent to a flare that meets the requirements in §63.11(b).	Maintaining visible emissions from a flare below a total of 5 minutes during any 2 consecutive hours.
2. Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent.	Maintaining a 98 percent by weight emission reduction of TOC or nonmethane TOC; or maintaining a TOC or nonmethane TOC concentration of not more than 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent.

[70 FR 6954, Feb. 9, 2005]

TABLE 21 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 21 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

[As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.]

For each applicable process vent for a new or existing catalytic reforming unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and purging operations by . . .
1. Option 1	Flare that meets the requirements in §63.11(b).	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.	Collecting flare monitoring data according to §63.1572; and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period.
2. Option 2	a. Thermal incinerator boiler or process heater with a design input capacity under 44 MW or boiler or process heater in which not all vent streams are not introduced into the flame zone. b. No control device	Maintain the daily average combustion zone temperature above the limit established during the performance test. Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum purging conditions that must be met prior to allowing uncontrolled purge releases.	Collecting, the hourly and daily temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test. Recording information to document compliance with the procedures in your operation, maintenance, and monitoring plan.

[70 FR 6954, Feb. 9, 2005]

TABLE 22 TO SUBPART UUU OF PART 63—INORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

As stated in §63.1567(a)(1), you shall meet each emission limitation in the following table that applies to you.

For . . .	You shall meet this emission limit for each applicable catalytic reforming unit process vent during coke burn-off and catalyst rejuvenation . . .
1. Each existing semi-regenerative catalytic reforming unit	Reduce uncontrolled emissions of hydrogen chloride (HCl) by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen.
2. Each existing cyclic or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.
3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.

[70 FR 6955, Feb. 9, 2005]

TABLE 23 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR INORGANIC HAP EMISSION LIMITATIONS FOR CATALYTIC REFORMING UNITS

As stated in §63.1567(a)(2), you shall meet each operating limit in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit with this type of control device . . .	You shall meet this operating limit during coke burn-off and catalyst rejuvenation . . .
1. Wet scrubber	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test.
2. Internal scrubbing system or no control device (e.g., hot regen system) meeting outlet HCl concentration limit.	The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test.

For each applicable process vent for a new or existing catalytic reforming unit with this type of control device . . .	You shall meet this operating limit during coke burn-off and catalyst rejuvenation . . .
3. Internal scrubbing system meeting HCl percent reduction standard.	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test.
4. Fixed-bed gas-solid adsorption system	The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test; and the HCl concentration in the adsorption system exhaust gas must not exceed the limit established during the performance test.
5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System).	The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test; and the weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™ System); and the weekly average chloride level on the sorbent leaving the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb™ System).

[70 FR 6955, Feb. 9, 2005]

TABLE 24 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

As stated in § 63.1567(b)(1), you shall meet each requirement in the following table that applies to you.

If you use this type of control device for your vent . . .	You shall install and operate this type of continuous monitoring system . . .
1. Wet scrubber	Continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the scrubber during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record gas flow rate entering or exiting the scrubber during coke burn-off and catalyst rejuvenation ¹ ; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation. ²
2. Internal scrubbing system or no control device (e.g., hot regen system) to meet HCl outlet concentration limit.	Colormetric tube sampling system to measure the HCl concentration in the catalyst regenerator exhaust gas during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart.
3. Internal scrubbing system to meet HCl percent reduction standard.	Continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation. ²
4. Fixed-bed gas-solid adsorption system	Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation; and colormetric tube sampling system to measure the gaseous HCl concentration in the adsorption system exhaust and at a point within the absorbent bed not to exceed 90 percent of the total length of the absorbent bed during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart.
5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System)	Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation.

¹ If applicable, you can use the alternative in § 63.1573 (a)(1) instead of a continuous parameter monitoring system for gas flow rate or instead of a continuous parameter monitoring system for the cumulative volume of gas.

² If applicable, you can use the alternative in § 63.1573(b)(1) instead of a continuous parameter monitoring system for pH of the water (or scrubbing liquid) or the alternative in § 63.1573(b)(2) instead of a continuous parameter monitoring system for alkalinity of the water (or scrubbing liquid).

[70 FR 6956, Feb. 9, 2005]

TABLE 25 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

As stated in § 63.1567(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
1. Any or no control system.	<p>a. Select sampling port location(s) and the number of traverse points.</p> <p>b. Determine velocity and volumetric flow rate.</p> <p>c. Conduct gas molecular weight analysis.</p> <p>d. Measure moisture content of the stack gas.</p> <p>e. Measure the HCl concentration at the selected sampling locations.</p>	<p>Method 1 or 1A (40 CFR part 60, appendix A), as applicable.</p> <p>Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable.</p> <p>Method 3, 3A, or 3B (40 CFR part 60, appendix A), as applicable.</p> <p>Method 4 (40 CFR part 60, appendix A).</p> <p>Method 26 or 26A (40 CFR part 60, appendix A). If your control device is a wet scrubber or internal scrubbing system, you must use Method 26A.</p>	<p>(1) If you operate a control device and you elect to meet an applicable HCl percent reduction standard, sampling sites must be located at the inlet of the control device or internal scrubbing system and at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series.</p> <p>(2) If you elect to meet an applicable HCl outlet concentration limit, locate sampling sites at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series. If there is no control device, locate sampling sites at the outlet of the catalyst regenerator prior to any release to the atmosphere.</p> <p>(1) For semi-regenerative and cyclic regeneration units, conduct the test during the coke burn-off and catalyst rejuvenation cycle, but collect no samples during the first hour or the last 6 hours of the cycle (for semi-regenerative units) or during the first hour or the last 2 hours of the cycle (for cyclic regeneration units). For continuous regeneration units, the test should be conducted no sooner than 3 days after process unit or control system start up.</p> <p>(2) Determine and record the HCl concentration corrected to 3 percent oxygen (using Equation 1 of § 63.1567) for each sampling location for each test run.</p> <p>(3) Determine and record the percent emission reduction, if applicable, using Equation 3 of § 63.1567 for each test run.</p> <p>(4) Determine and record the average HCl concentration (corrected to 3 percent oxygen) and the average percent emission reduction, if applicable, for the overall source test from the recorded test run values.</p>

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Pt. 63, Subpt. UUU, Table 25

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
2. Wet scrubber	<p>a. Establish operating limit for pH level or alkalinity.</p> <p>b. Establish operating limit for liquid-to-gas ratio.</p>	<p>i. Data from continuous parameter monitoring systems.</p> <p>ii. Alternative pH procedure in § 63.1573(b)(1).</p> <p>iii. Alternative alkalinity method in § 63.1573(b)(2).</p> <p>i. Data from continuous parameter monitoring systems.</p> <p>ii. Alternative procedure for gas flow rate in § 63.1573(a)(1).</p>	<p>Measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting scrubber every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.</p> <p>Measure and record the pH of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.</p> <p>Measure and record the alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.</p> <p>Measure and record the gas flow rate entering or exiting the scrubber and the total water (or scrubbing liquid) flow rate entering the scrubber every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values.</p> <p>Collect air flow rate monitoring data or determine the air flow rate using control room instruments every 15 minutes during the entire period of the initial performance test. Determine and record the hourly average rate of all the readings. Determine and record the maximum gas flow rate using Equation 1 of § 63.1573.</p>
3. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl outlet concentration limit.	Establish operating limit for HCl concentration.	Data from continuous parameter monitoring system.	Measure and record the HCl concentration in the catalyst regenerator exhaust gas using the colorimetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages. Determine and record the operating limit for HCl concentration using Equation 4 of § 63.1567.
4. Internal scrubbing system meeting HCl percent reduction standard.	a. Establish operating limit for pH level or alkalinity.	<p>i. Data from continuous parameter monitoring system.</p> <p>ii. Alternative pH method in § 63.1573(b)(1).</p> <p>iii. Alternative alkalinity method in § 63.1573(b)(2).</p>	<p>Measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.</p> <p>Measure and in record pH of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.</p> <p>Measure and record the alkalinity water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.</p>

Pt. 63, Subpt. UUU, Table 26

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For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
5. Fixed-bed gas-solid adsorption system. Gas-solid.	<p>b. Establish operating limit for liquid-to-gas ratio.</p> <p>a. Establish operating limit for temperature.</p> <p>b. Establish operating limit for HCl concentration.</p>	<p>Data from continuous parameter monitoring systems.</p> <p>Data from continuous parameter monitoring system.</p> <p>i. Data from continuous parameter monitoring systems.</p>	<p>Measure and record the gas entering or exiting the internal scrubbing system and the total water (or scrubbing liquid) flow rate entering the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values.</p> <p>Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes. Determine and record the maximum hourly average temperature.</p> <p>(1) Measure and record the HCl concentration in the exhaust gas from the fixed-bed adsorption system using the colometric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages.</p> <p>(2) If you elect to comply with the HCl outlet concentration limit (Option 2), determine and record the operating limit for HCl concentration using Equation 4 of § 63.1567. If you elect to comply with the HCl percent reduction standard (Option 1), determine and record the operating limit for HCl concentration using Equation 5 of § 63.1567.</p>
6. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System).	<p>a. Establish operating limit for temperature.</p> <p>b. Measure the chloride level on the sorbent entering and exiting the adsorption system.</p>	<p>Data from continuous parameter monitoring systems.</p> <p>Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to subpart UUU; or EPA Method 5050 combined either with EPA Method 9056, or with EPA Method 9253; or EPA Method 9212 with the soil extraction procedures listed within the method.¹</p>	<p>Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes. Determine and record the maximum hourly average temperature.</p> <p>Measure and record the chloride concentration of the sorbent material entering and exiting the adsorption system at least three times during each test run. Determine and record the average weight percent chloride concentration of the sorbent entering the adsorption system for each test run. Determine and record the average weight percent chloride concentration of the sorbent exiting the adsorption system for each test run.</p>

¹ The EPA Methods 5050, 9056, 9212 and 9253 are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5295 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B-108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. These methods are also available at <http://www.epa.gov/epaoswer/hazwaste/test/main.htm>.

[70 FR 6956, Feb. 9, 2005]

TABLE 26 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH INORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

As stated in § 63.1567(b)(4), you shall meet each requirement in the following table that applies to you.

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Pt. 63, Subpt. UUU, Table 28

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .	For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Each existing semi-regenerative catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen.	Average emissions HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 92 percent or to a concentration less than or equal to 30 ppmv (dry basis) corrected to 3 percent oxygen.	2. Each existing cyclic or continuous catalytic reforming unit and each new semi-regenerative, cyclic, or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.	Average emissions of HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 97 percent or to a concentration less than or equal to 10 ppmv (dry basis) corrected to 3 percent oxygen.

[70 FR 6959, Feb. 9, 2005]

TABLE 27 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH INORGANIC HAP EMISSION LIMITS FOR CATALYTIC REFORMING UNITS

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .	For . . .	For this emission limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .
1. Each existing semi-regenerative catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen.	Maintaining a 92 percent HCl emission reduction or an HCl concentration no more than 30 ppmv (dry basis), corrected to 3 percent oxygen.	3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.	Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen.
2. Each existing cyclic or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.	Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen.			

[70 FR 6960, Feb. 9, 2005]

TABLE 28 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 28 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS

[As stated in § 63.1567(c)(1), you shall meet each requirement in the following table that applies to you.]

For each new and existing catalytic reforming unit using this type of control device or system	For this operating limit	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by
1. Wet scrubber	<p>a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the level established during the performance test.</p> <p>b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test.</p>	<p>Collecting the hourly and daily average pH or alkalinity monitoring data according to § 63.1572¹; and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.</p> <p>Collecting the hourly average gas flow rate² and total water (or scrubbing liquid) flow rate monitoring data according to § 63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.</p>
2. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl concentration limit.	The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test.	Measuring and recording the HCl concentration at least 4 times during a regeneration cycle (equally spaced in time) or every 4 hours, whichever is more frequent, using a colorimetric tube sampling system; calculating the daily average HCl concentration as an arithmetic average of all samples collected in each 24-hour period from the start of the coke burn-off cycle or for the entire duration of the coke burn-off cycle if the coke burn-off cycle is less than 24 hours; and maintaining the daily average HCl concentration below the applicable operating limit.
3. Internal scrubbing system meeting percent HCl reduction standard.	<p>a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test.</p> <p>b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test.</p>	<p>Collecting the hourly and daily average pH or alkalinity monitoring data according to § 63.1572¹ and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.</p> <p>Collecting the hourly average gas flow rate² and total water (or scrubbing liquid) flow rate monitoring data according to § 63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.</p>
4. Fixed-bed gas-solid adsorption systems.	<p>a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test.</p> <p>b. The HCl concentration in the exhaust gas from the fixed-bed gas-solid adsorption system must not exceed the limit established during the performance test.</p>	<p>Collecting the hourly and daily average temperature monitoring data according to § 63.1572; and maintaining the daily average temperature below the operating limit established during the performance test.</p> <p>Measuring and recording the concentration of HCl weekly or during each regeneration cycle, whichever is less frequent, using a colorimetric tube sampling system at a point within the adsorbent bed not to exceed 90 percent of the total length of the adsorption bed during coke burn-off and catalyst rejuvenation; implementing procedures in the operating and maintenance plan if the HCl concentration at the sampling location within the adsorption bed exceeds the operating limit; and maintaining the HCl concentration in the gas from the adsorption system below the applicable operating limit.</p>
5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System).	a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test.	Collecting the hourly and daily average temperature monitoring data according to § 63.1572; and maintaining the daily average temperature below the operating limit established during the performance test.

TABLE 28 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR INORGANIC HAP EMISSIONS FROM CATALYTIC REFORMING UNITS—Continued

[As stated in § 63.1567(c)(1), you shall meet each requirement in the following table that applies to you.]

For each new and existing catalytic reforming unit using this type of control device or system . . .	For this operating limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .
	b. The weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™.	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride ³ ; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™ System).
	c. The weekly average chloride level on the sorbent exiting the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb™ System).	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride concentration; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.8 weight percent Chlorsorb™ System).

¹If applicable, you can use either alternative in § 63.1573(b) instead of a continuous parameter monitoring system for pH or alkalinity if you used the alternative method in the initial performance test.

²If applicable, you can use the alternative in § 63.1573(a)(1) instead of a continuous parameter monitoring system for the gas flow rate or cumulative volume of gas entering or exiting the system if you used the alternative method in the initial performance test.

³The total chloride concentration of the sorbent material must be measured by the procedure, "Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)" in appendix A to this subpart; or by using EPA Method 5050, Bomb Preparation Method for Solid Waste, combined either with EPA Method 9058, Determination of Inorganic Anions by Ion Chromatography, or with EPA Method 9253, Chloride (Titrimetric, Silver Nitrate); or by using EPA Method 9212, Potentiometric Determination of Chloride in Aqueous Samples with Ion-Selective Electrode, and using the soil extraction procedures listed within the method. The EPA Methods 5050, 9058, 9212 and 9253 are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW-846, Revision 5 (April 1988). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B-108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. These methods are also available at <http://www.epa.gov/epaoswer/hazwaste/test/main.htm>.

[70 FR 6954, Feb. 9, 2005]

TABLE 29 TO SUBPART UUU OF PART 63—HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

As stated in § 63.1568(a)(1), you shall meet each emission limitation in the following table that applies to you.

For . . .	You shall meet this emission limit for each process vent . . .
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	a. 250 ppmv (dry basis) of sulfur dioxide (SO ₂) at zero percent excess air if you use an oxidation or reduction control system followed by incineration. b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.
2. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2); Option 1 (Elect NSPS).	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration. b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.
3. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in paragraph (a)(2) of 40 CFR 60.104; Option 2 (TRS limit).	300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO ₂ concentration (dry basis) at zero percent oxygen.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 30 TO SUBPART UUU OF PART 63—OPERATING LIMITS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS

As stated in §63.1568(a)(2), you shall meet each operating limit in the following table that applies to you.

For . . .	If use this type of control device	You shall meet this operating limit. . .
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	Not applicable	Not applicable.
2. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2): Option 1 (Elect NSPS).	Not applicable	Not applicable.
3. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2): Option 2 (TRS limit).	Thermal incinerator	Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 31 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS

As stated in §63.1568(b)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	<p>a. 250 ppmv (dry basis) of SO₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration.</p> <p>b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.</p>	<p>Continuous emission monitoring system to measure and record the hourly average concentration of SO₂ (dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.</p> <p>Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and oxygen (O₂) emissions. Calculate the reduced sulfur emissions as SO₂ (dry basis) at zero percent excess air. <i>Exception:</i> You can use an instrument having an air or SO₂ dilution and oxidation system to convert the reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO₂ instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.</p>
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in paragraph (a) (2) of 40 CFR 60.104.	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of SO ₂ (dry basis), at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	<p>b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.</p> <p>300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO₂ concentration (dry basis) at zero percent oxygen.</p>	<p>Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and O₂ emissions for each exhaust stack. Calculate the reduced sulfur emissions as SO₂ (dry basis), at zero percent excess air. <i>Exception:</i> You can use an instrument having an air or O₂ dilution and oxidation system to convert the reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO₂ instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.</p> <p>i. Continuous emission monitoring system to measure and record the hourly average concentration of TRS for each exhaust stack; this monitor must include an oxygen monitor for correcting the data for excess oxygen; or</p> <p>ii. Continuous parameter monitoring systems to measure and record the combustion zone temperature of each thermal incinerator and the oxygen content (percent, dry basis) in the vent stream of the incinerator.</p>

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6961, Feb. 9, 2005]

TABLE 32 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS NOT SUBJECT TO THE NEW SOURCE PERFORMANCE STANDARDS FOR SULFUR OXIDES

As stated in §63.1568(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For . . .	You must . . .	Using . . .	According to these requirements . . .
1. Each new and existing sulfur recovery unit: Option 1 (Elect NSPS).	Measure SO ₂ concentration (for an oxidation or reduction system followed by incineration) or the concentration of reduced sulfur (or SO ₂ if you use an instrument to convert the reduced sulfur to SO ₂) for a reduction control system without incineration.	Data from continuous emission monitoring system.	Collect SO ₂ monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
2. Each new and existing sulfur recovery unit: Option 2 (TRS limit).	<p>a. Select sampling port's location and the number of traverse ports.</p> <p>b. Determine velocity and volumetric flow rate.</p> <p>c. Conduct gas molecular weight analysis; obtain the oxygen concentration needed to correct the emission rate for excess air.</p> <p>d. Measure moisture content of the stack gas.</p>	<p>Method 1 or 1A appendix A to part 60 of this chapter.</p> <p>Method 2, 2A, 2C, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable.</p> <p>Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable.</p> <p>Method 4 in appendix A to part 60 of this chapter.</p>	<p>Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.</p> <p>Take the samples simultaneously with reduced sulfur or moisture samples.</p> <p>Make your sampling time for each Method 4 sample equal to that for 4 Method 15 samples.</p>

For . . .	You must . . .	Using . . .	According to these requirements . . .
	e. Measure the concentration of TRS.	Method 15 or 15A in appendix A to part 60 of this chapter, as applicable.	If the cross-sectional area of the duct is less than 5 square meters (m ²) or 54 square feet, you must use the centroid of the cross section as the sampling point. If the cross-sectional area is 5 m ² or more and the centroid is more than 1 meter (m) from the wall, your sampling point may be at a point no closer to the walls than 1 m or 39 inches. Your sampling rate must be at least 3 liters per minute or 0.10 cubic feet per minute to ensure minimum residence time for the sample inside the sample lines.
	f. Calculate the SO ₂ equivalent for each run after correcting for moisture and oxygen.	The arithmetic average of the SO ₂ equivalent for each sample during the run.	
	g. Correct the reduced sulfur samples to zero percent excess air.	Equation 1 of § 63.1568.	
	h. Establish each operating limit in Table 30 of this subpart that applies to you.	Data from the continuous parameter monitoring system.	
	i. Measure thermal incinerator: combustion zone temperature.	Data from the continuous parameter monitoring system.	Collect temperature monitoring data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average temperature from all the readings.
	j. Measure thermal incinerator: oxygen concentration (percent, dry basis) in the vent stream.	Data from the continuous parameter monitoring system.	Collect oxygen concentration (percent, dry basis) data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average percent excess oxygen concentration.
	k. If you use a continuous emission monitoring system, measure TRS concentration.	Data from continuous emission monitoring system.	Collect TRS data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 33 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

As stated in § 63.1568(b)(5), you shall meet each requirement in the following table that applies to you.

TABLE 33 TO SUBPART UUU OF PART 63.—INITIAL COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

[As stated in § 63.1568(b)(5), you shall meet each requirement in the following table that applies to you.]

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	<p>a. 250 ppmv (dry basis) SO₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration.</p> <p>b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.</p>	<p>You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of SO₂ emissions measured by the continuous emission monitoring system is less than or equal to 250 ppmv (dry basis) at zero percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the SO₂ limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in § 63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.</p> <p>You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of reduced sulfur compounds measured by your continuous emission monitoring system is less than or equal to 300 ppmv, calculated as ppmv SO₂ (dry basis) at zero percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the SO₂ limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in § 63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.</p>
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Each 12-hour rolling average concentration of SO ₂ emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 250 ppmv (dry basis) at zero percent excess air, and your performance evaluation shows the monitoring system meets the applicable requirements in § 63.1572.

TABLE 33 TO SUBPART UUU OF PART 63.—INITIAL COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS—Continued

[As stated in § 63.1568(b)(5), you shall meet each requirement in the following table that applies to you.]

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	<p>b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.</p> <p>300 ppmv of TRS compounds expressed as an equivalent SO₂ concentration (dry basis) at zero percent oxygen.</p>	<p>Each 12-hour rolling average concentration of reduced sulfur compounds measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv, calculated as ppmv SO₂ (dry basis) at zero percent excess air; and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in § 63.1572.</p> <p>If you use continuous parameter monitoring systems, the average concentration of TRS emissions measured using Method 15 during the initial performance test is less than or equal to 300 ppmv expressed as equivalent SO₂ concentration (dry basis) at zero percent oxygen. If you use a continuous emission monitoring system, each 12-hour rolling average concentration of TRS emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv expressed as an equivalent SO₂ (dry basis) at zero percent oxygen; and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in § 63.1572.</p>

[70 FR 6962, Feb. 9, 2005]

TABLE 34 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

As stated in § 63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

TABLE 34 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS

[As stated in § 63.1568(c)(1), you shall meet each requirement in the following table that applies to you.]

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance by . . .
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Collecting the hourly average SO ₂ monitoring data (dry basis, percent excess air) according to § 63.1572; determining and recording each 12-hour rolling average concentration of SO ₂ ; maintaining each 12-hour rolling average concentration of SO ₂ at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO ₂ greater than the applicable emission limitation in the compliance report required by § 63.1575.

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TABLE 34 TO SUBPART UUU OF PART 63.—CONTINUOUS COMPLIANCE WITH HAP EMISSION LIMITS FOR SULFUR RECOVERY UNITS—Continued

(As stated in § 63.1568(c)(1), you shall meet each requirement in the following table that applies to you.)

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance by . . .
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Collecting the hourly average reduced sulfur (and air or O ₂ dilution and oxidation) monitoring data according to § 63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the compliance report required by § 63.1575.
	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration.	Collecting the hourly average SO ₂ data (dry basis, percent excess air) according to § 63.1572; determining and recording each 12-hour rolling average concentration of SO ₂ ; maintaining each 12-hour rolling average concentration of SO ₂ at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO ₂ greater than the applicable emission limitation in the compliance report required by § 63.1575.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Collecting the hourly average reduced sulfur (and air or O ₂ dilution and oxidation) monitoring data according to § 63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the compliance report required by § 63.1575.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	300 ppmv of TRS compounds, expressed as an SO ₂ concentration (dry basis) at zero percent oxygen or reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air.	i. If you use continuous parameter monitoring systems, collecting the hourly average TRS monitoring data according to § 63.1572 and maintaining each 12-hour average concentration of TRS at or below the applicable emission limitation; or
		ii. If you use a continuous emission monitoring system, collecting the hourly average TRS monitoring data according to § 63.1572, determining and recording each 12-hour rolling average concentration of TRS; maintaining each 12-hour rolling average concentration of TRS at or below the applicable emission limitation; and reporting any 12-hour rolling average TRS concentration greater than the applicable emission limitation in the compliance report required by § 63.1575.

[70 FR 6963, Feb. 9, 2005]

TABLE 35 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH OPERATING LIMITS FOR HAP EMISSIONS FROM SULFUR RECOVERY UNITS

As stated in § 63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

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For . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in paragraph 40 CFR 60.104(a)(2).	Not applicable	Meeting the requirements of Table 34 of this subpart.
2. Option 1: Elect NSPS Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	Not applicable	Meeting the requirements of Table 34 of this subpart.
3. Option 2: TRS limit Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2).	<p>a. Maintain the daily average combustion zone temperature above the level established during the performance test.</p> <p>b. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test.</p>	<p>Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature at or above the limit established during the performance test.</p> <p>Collecting the hourly and daily average O₂ monitoring data according to §63.1572; and maintaining the average O₂ concentration above the level established during the performance test.</p>

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 36 TO SUBPART UUU OF PART 63—WORK PRACTICE STANDARDS FOR HAP EMISSIONS FROM BYPASS LINES

As stated in §63.1569(a)(1), you shall meet each work practice standard in the following table that applies to you.

Option	You shall meet one of these equipment standards . . .
1. Option 1	Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in the by bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.
2. Option 2	Install a car-seat or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device.
3. Option 3	Seal the bypass line by installing a solid blind between piping flanges.
4. Option 4	Vent the bypass line to a control device that meets the appropriate requirements in this subpart.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6964, Feb. 9, 2005]

TABLE 37 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR BYPASS LINES

As stated in §63.1569(b)(1), you shall meet each requirement in the following table that applies to you.

For this standard . . .	You shall . . .
1. Option 1: Install and operate a flow indicator, level recorder, or electronic valve position monitor.	Record during the performance test for each type of control device whether the flow indicator, level recorder, or electronic valve position monitor was operating and whether flow was detected at any time during each hour of level the three runs comprising the performance test.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 38 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH WORK PRACTICE STANDARDS FOR HAP EMISSIONS FROM BYPASS LINES

As stated in §63.1569(b)(2), you shall meet each requirement in the following table that applies to you.

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TABLE 38 TO SUBPART UUU OF PART 63.—INITIAL COMPLIANCE WITH WORK PRACTICE STANDARDS FOR HAP EMISSIONS FROM BYPASS LINES

[As stated in § 63.1569(b)(2), you shall meet each requirement in the following table that applies to you.]

Option . . .	For this work practice standard . . .	You have demonstrated initial compliance if . . .
1. Each new or existing bypass line associated with a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit.	<p>a. Option 1: Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.</p> <p>b. Option 2: Install a car-seal or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper lever) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device.</p> <p>c. Option 3: Seal the bypass line by installing a solid blind between piping flanges.</p> <p>d. Option 4: Vent the bypass line to a control device that meets the appropriate requirements in this subpart.</p>	<p>The installed equipment operates properly during each run of the performance test and no flow is present in the line during the test.</p> <p>As part of the notification of compliance status, you certify that you installed the equipment, the equipment was operational by your compliance date, and you identify what equipment was installed.</p> <p>See item 1.b of this table.</p> <p>See item 1.b of this table.</p>

[70 FR 6965, Feb. 9, 2005]

TABLE 39 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH WORK PRACTICE STANDARDS FOR HAP EMISSIONS FROM BYPASS LINES

As stated in § 63.1569(c)(1), you shall meet each requirement in the following table that applies to you.

If you elect this standard . . .	You shall demonstrate continuous compliance by . . .
1. Option 1: Flow indicator, level recorder, or electronic valve position monitor.	Monitoring and recording on a continuous basis or at least every hour whether flow is present in the bypass line; visually inspecting the device at least once every hour if the device is not equipped with a recording system that provides a continuous record; and recording whether the device is operating properly and whether flow is present in the bypass line.
2. Option 2: Car-seal or lock-and-key device	Visually inspecting the seal or closure mechanism at least once every month; and recording whether the bypass line valve is maintained in the closed position and whether flow is present in the line.
3. Option 3: Solid blind flange	Visually inspecting the blind at least once a month; and recording whether the blind is maintained in the correct position such that the vent stream cannot be diverted through the bypass line.
4. Option 4: Vent to control device	Monitoring the control device according to appropriate subpart requirements.
5. Option 1, 2, 3, or 4	Recording and reporting the time and duration of any bypass.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6965, Feb. 9, 2005]

TABLE 40 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR INSTALLATION, OPERATION, AND MAINTENANCE OF CONTINUOUS OPACITY MONITORING SYSTEMS AND CONTINUOUS EMISSION MONITORING SYSTEMS

As stated in § 63.1572(a)(1) and (b)(1), you shall meet each requirement in the following table that applies to you.

This type of continuous opacity or emission monitoring system	Must meet these requirements . . .
1. Continuous opacity monitoring system	Performance specification 1 (40 CFR part 60, appendix B).

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40 CFR Ch. I (7-1-05 Edition)

This type of continuous opacity or emission monitoring system . . .	Must meet these requirements . . .
2. CO continuous emission monitoring system	Performance specification 4 (40 CFR part 60, appendix B); span value of 1,000 ppm; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
3. CO continuous emission monitoring system used to demonstrate emissions average under 50 ppm (dry basis).	Performance specification 4 (40 CFR part 60, appendix B); and span value of 100 ppm.
4. SO ₂ continuous emission monitoring system for sulfur recovery unit with oxidation control system or reduction control system; this monitor must include an O ₂ monitor for correcting the data for excess air.	Performance specification 2 (40 CFR part 60, appendix B); span value of 500 ppm SO ₂ ; use Methods 6 or 6C and 3A or 3B (40 CFR part 60, appendix A) for certifying O ₂ monitor; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
5. Reduced sulfur and O ₂ continuous emission monitoring system for sulfur recovery unit with reduction control system not followed by incineration; this monitor must include an O ₂ monitor for correcting the data for excess air unless exempted.	Performance specification 5 (40 CFR part 60, appendix B), except calibration drift specification is 2.5 percent of the span value instead of 5 percent; 450 ppm reduced sulfur; use Methods 15 or 15A and 3A or 3B (40 CFR part 60, appendix A) for certifying O ₂ monitor; if Method 3A or 3B yields O ₂ concentrations below 0.25 percent during the performance evaluation, the O ₂ concentration can be assumed to be zero and the O ₂ monitor is not required; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
6. Instrument with an air or O ₂ dilution and oxidation system to convert reduced sulfur to SO ₂ for continuously monitoring the concentration of SO ₂ instead of reduced sulfur monitor and O ₂ monitor.	Performance specification 5 (40 CFR part 60, appendix B); span value of 375 ppm SO ₂ ; use Methods 15 or 15A and 3A or 3B for certifying O ₂ monitor; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
7. TRS continuous emission monitoring system for sulfur recovery unit; this monitor must include an O ₂ monitor for correcting the data for excess air.	Performance specification 5 (40 CFR part 60, appendix B).
8. O ₂ monitor for oxygen concentration.	If necessary due to interferences, locate the oxygen sensor prior to the introduction of any outside gas stream; performance specification 3 (40 CFR part 60, appendix B); and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6965, Feb. 9, 2005]

TABLE 41 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR INSTALLATION, OPERATION, AND MAINTENANCE OF CONTINUOUS PARAMETER MONITORING SYSTEMS

As stated in §63.1572(c)(1), you shall meet each requirement in the following table that applies to you.

If you use . . .	You shall . . .	If you use . . .	You shall . . .
1. pH strips	Use pH strips with an accuracy of ± 10 percent.	2. Colometric tube sampling system.	Use a colometric tube sampling system with a printed numerical scale in ppmv, a standard measurement range of 1 to 10 ppmv (or 1 to 30 ppmv if applicable), and a standard deviation for measured values of no more than ± 15 percent. System must include a gas detection pump and hot air probe if needed for the measurement range.

[70 FR 6966, Feb. 9, 2005]

TABLE 42 TO SUBPART UUU OF PART 63—ADDITIONAL INFORMATION FOR INITIAL NOTIFICATION OF COMPLIANCE STATUS

As stated in §63.1574(d), you shall meet each requirement in the following table that applies to you.

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For . . .	You shall provide this additional information . . .
1. Identification of affected sources and emission points.	Nature, size, design, method of operation, operating design capacity of each affected source; identify each emission point for each HAP; identify any affected source or vent associated with an affected source not subject to the requirements of subpart UUU.
2. Initial compliance	Identification of each emission limitation you will meet for each affected source, including any option you select (i.e., NSPS, PM or Ni, flare, percent reduction, concentration, options for bypass lines); if applicable, certification that you have already conducted a performance test to demonstrate initial compliance with the NSPS for an affected source; certification that the vents meet the applicable emission limit and the continuous opacity or that the emission monitoring system meets the applicable performance specification; if applicable, certification that you have installed and verified the operational status of equipment by your compliance date for each bypass line that meets the requirements of Option 2, 3, or 4 in § 63.1569 and what equipment you installed; identification of the operating limit for each affected source, including supporting documentation; if your affected source is subject to the NSPS, certification of compliance with NSPS emission limitations and performance specifications; a brief description of performance test conditions (capacity, feed quality, catalyst, etc.); an engineering assessment (if applicable); and if applicable, the flare design (e.g., steam-assisted, air-assisted, or non-assisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the Method 22 test.
3. Continuous compliance	Each monitoring option you elect; and identification of any unit or vent for which monitoring is not required; and the definition of "operating day." (This definition, subject to approval by the applicable permitting authority, must specify the times at which a 24-hr operating day begins and ends.)

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 43 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR REPORTS

As stated in § 63.1575(a), you shall meet each requirement in the following table that applies to you.

You must submit a(n) . . .	The report must contain . . .	You shall submit the report . . .
1. Compliance report	If there are not deviations from any emission limitation or work practice standard that applies to you, a statement that there were no deviations from the standards during the reporting period and that no continuous opacity monitoring system or continuous emission monitoring system was inoperative, inactive, out-of-control, repaired, or adjusted; and if you have a deviation from any emission limitation or work practice standard during the reporting period, the report must contain the information in § 63.1575(d) or (e)	Semiannually according to the requirements in § 63.1575(b).

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU

As stated in § 63.1577, you shall meet each requirement in the following table that applies to you.

Citation	Subject	Applies to subpart UUU	Explanation
§ 63.1	Applicability	Yes	Except that subpart UUU specifies calendar or operating day.
§ 63.2	Definitions	Yes.	
§ 63.3	Units and Abbreviations	Yes.	
§ 63.4	Prohibited Activities	Yes.	
§ 63.5(A)–(C)	Construction and Reconstruction.	Yes	In § 63.5(b)(4), replace the reference to § 63.9 with § 63.9(b)(4) and (5).
§ 63.5(d)(1)(i)	Application for Approval of Construction or Reconstruction—General Application Requirements.	Yes	Except, subpart UUU specifies the application is submitted as soon as practicable before start-up but not later than 90 days (rather than 60) after the promulgation date where construction or reconstruction had commenced and initial startup had not occurred before promulgation.

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Citation	Subject	Applies to subpart UUU	Explanation
§ 63.5(d)(1)(ii)	Yes	Except that emission estimates specified in § 63.5(d)(1)(ii)(H) are not required. Subpart UUU specifies submission of notification of compliance status.
§ 63.5(d)(1)(iii)	No	
§ 63.5(d)(2)	No.	Except that § 63.5(d)(3)(ii) does not apply.
§ 63.5(d)(3)	Yes	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Approval of Construction or Reconstruction.	Yes.	Except that 60 days is changed to 90 days and cross-reference to 53.9(B)(2) does not apply.
§ 63.5(f)(1)	Approval of Construction or Reconstruction Based on State Review.	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Compliance with Standards and Maintenance—Applicability.	Yes.	Except that subpart UUU specifies different compliance dates for sources.
§ 63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed Sources.	Yes.	
§ 63.6(b)(5)	Yes	
§ 63.6(b)(6)	[Reserved]	Not applicable.	Except that subpart UUU specifies different compliance dates for sources subject to Tier II gasoline sulfur control requirements.
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major.	Yes.	
§ 63.6(c)(1)–(2)	Compliance Dates for Existing Sources.	Yes	
§ 63.6(c)(3)–(4)	[Reserved]	Not applicable.	Except that reports of actions not consistent with plan are not required within 2 and 7 days of action but rather must be included in next periodic report.
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major.	Yes.	
§ 63.6(d)	[Reserved]	Not applicable.	
§ 63.6(e)(1)–(2)	Operation and Maintenance Requirements.	Yes.	The owner or operator is only required to keep the latest version of the plan.
§ 63.6(e)(3)(i)–(iii)	Startup, Shutdown, and Malfunction Plan.	Yes.	
§ 63.6(e)(3)(iv)	Yes	
§ 63.6(e)(3)(v)–(viii)	Yes	Subpart UUU specifies methods.
§ 63.6(f)(1)–(2)(iii)(C)	Compliance with Emission Standards.	Yes.	
§ 63.6(f)(2)(iii)(D)	No.	
§ 63.6(f)(2)(iv)–(v)	Yes.	Applies to Method 22 tests.
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Alternative Standard	Yes.	
§ 63.6(h)	Opacity/VE Standards	Yes.	Applies to Method 22 observations.
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards.	No	
§ 63.6(h)(2)(ii)	[Reserved]	Not applicable.	
§ 63.6(h)(2)(iii)	Yes.	Applies to Method 22 observations.
§ 63.6(h)(3)	[Reserved]	Not applicable.	
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date.	Yes	
§ 63.6(h)(5)	Conducting Opacity/VE Observations.	No.	Applies to Method 22 observations.
§ 63.6(h)(6)	Records of Conditions During Opacity/VE Observations.	Yes	
§ 63.6(h)(7)(i)	Report COM Monitoring Data from Performance Test.	Yes.	
§ 63.6(h)(7)(ii)	Using COM Instead of Method 9.	No.	

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Citation	Subject	Applies to subpart UUU	Explanation
§ 63.6(h)(7)(iii)	Averaging Time for COM during Performance Test.	Yes.	
§ 63.6(h)(7)(iv)	COM Requirements	Yes.	
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Yes.	
§ 63.6(h)(9)	Adjusted Opacity Standard.	Yes.	
§ 63.6(i)(1)-(14)	Extension of Compliance.	Yes	Extension of compliance under § 63.6(i)(4) not applicable to a facility that installs catalytic cracking feed hydrotreating and receives an extended compliance date under § 63.1563(c).
§ 63.6(j)(15)	[Reserved]	Not applicable.	
§ 63.6(j)(16)		Yes.	
§ 63.6(j)	Presidential Compliance Exemption.	Yes.	
§ 63.7(a)(1)	Performance Test Requirements Applicability.	Yes	Except that subpart UUU specifies the applicable test and demonstration procedures.
§ 63.7(a)(2)	Performance Test Dates.	No	Test results must be submitted in the Notification of Compliance Status report due 150 days after the compliance date.
§ 63.7(a)(3)	Section 114 Authority ...	Yes.	
§ 63.7(b)	Notifications	Yes	Except that subpart UUU specifies notification at least 30 days prior to the scheduled test date rather than 60 days.
§ 63.7(c)	Quality Assurance Program/Site-Specific Test Plan.	Yes.	
§ 63.7(d)	Performance Test Facilities.	Yes.	
§ 63.7(e)	Conduct of Tests	Yes.	
§ 63.7(f)	Alternative Test Method	Yes.	
§ 63.7(g)	Data Analysis, Record-keeping, Reporting.	Yes	Except performance test reports must be submitted with notification of compliance status due 150 days after the compliance date.
§ 63.7(h)	Waiver of Tests	Yes.	
§ 63.8(a)(1)	Monitoring Requirements-Applicability.	Yes.	
§ 63.8(a)(2)	Performance Specifications.	Yes.	
§ 63.8(a)(3)	[Reserved]	Not applicable.	
§ 63.8(a)(4)	Monitoring with Flares ..	Yes.	
§ 63.8(b)(1)	Conduct of Monitoring ..	Yes.	
§ 63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems.	Yes	Subpart UUU specifies the required monitoring locations.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance.	Yes.	
§ 63.8(c)(1)(i)-(ii)	Startup, Shutdown, and Malfunctions.	Yes	Except that subpart UUU specifies that reports are not required if actions are consistent with the SSM plan, unless requested by the permitting authority. If actions are not consistent, actions must be described in next compliance report.
§ 63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	Yes.	
§ 63.8(c)(2)-(3)	Monitoring System Installation.	Yes	Except that subpart UUU specifies that for continuous parameter monitoring systems, operational status verification includes completion of manufacturer written specifications or installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment will monitor accurately.
§ 63.8(c)(4)	Continuous Monitoring System Requirements.	No	Subpart UUU specifies operational requirements.

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Citation	Subject	Applies to subpart UUU	Explanation
§ 63.8(c)(4)(i)-(ii)	Continuous Monitoring System Requirements.	Yes	Except that these requirements apply only to a continuous opacity monitoring system or a continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or SO ₂ limits.
§ 63.8(c)(5)	COM Minimum Procedures.	Yes.	
§ 63.8(c)(6)	CMS Requirements	No	Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or SO ₂ limits.
§ 63.8(c)(7)-(8)	CMS Requirements	Yes.	
§ 63.8(d)	Quality Control Program	Yes	Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or SO ₂ limits.
§ 63.8(e)	CMS Performance Evaluation.	Yes	Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or SO ₂ limits. Results are to be submitted as part of the Notification Compliance Status due 150 days after the compliance date.
§ 63.8(f)(1)-(5)	Alternative Monitoring Methods.	Yes	Except that subpart UUU specifies procedures for requesting alternative monitoring systems and alternative parameters.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test.	Yes	Applicable to continuous emission monitoring systems if performance specification requires a relative accuracy test audit.
§ 63.8(g)(1)-(4)	Reduction of Monitoring Data.	Yes	Applies to continuous opacity monitoring system or continuous emission monitoring system.
§ 63.8(g)(5)	Data Reduction	No	Subpart UUU specifies requirements.
§ 63.9(a)	Notification Requirements—Applicability.	Yes	Duplicate Notification of Compliance Status report to the Regional Administrator may be required.
§ 63.9(b)(1)-(2), (4)-(5)	Initial Notifications	Yes	Except that notification of construction or reconstruction is to be submitted as soon as practicable before startup but no later than 30 days (rather than 60 days) after the effective date if construction or reconstruction had commenced but startup had not occurred before the effective date.
§ 63.9(b)(3)	[Reserved].		
§ 63.9(c)	Request for Extension of Compliance.	Yes.	
§ 63.9(d)	New Source Notification for Special Compliance Requirements.	Yes.	
§ 63.9(e)	Notification of Performance Test.	Yes	Except that notification is required at least 30 days before test.
§ 63.9(f)	Notification of VE/Opacity Test.	Yes.	
§ 63.9(g)	Additional Notification Requirements for Sources with Continuous Monitoring Systems.	Yes	Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or SO ₂ limits.
§ 63.9(h)	Notification of Compliance Status.	Yes	Except that subpart UUU specifies the notification is due no later than 150 days after compliance date.
§ 63.9(i)	Adjustment of Deadlines.	Yes.	
§ 63.9(j)	Change in Previous Information.	Yes.	
63.10(a)	Recordkeeping and Reporting Applicability.	Yes.	

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Citation	Subject	Applies to subpart UUU	Explanation
§ 63.10(b)	Records	Yes	Except that § 63.10(b)(2)(xii) applies if you use a continuous emission monitoring system to meet the NSPS or you select to meet the NSPS, CO, or SO ₂ reduced sulfur limit and the performance evaluation requires a relative accuracy test audit.
§ 63.10(c)(1)-(6), (9)-(15)	Additional Records for Continuous Monitoring Systems.	Yes	Except that these requirements apply if you use a continuous opacity monitoring system or a continuous emission monitoring system to meet the NSPS or elect to meet the NSPS opacity, CO, or SO ₂ limits.
§ 63.10(c)(7)-(8)	Records of Excess Emissions and Exceedances.	No	Subpart UUU specifies requirements.
§ 63.10(d)(1)	General Reporting Requirements.	Yes.	
§ 63.10(d)(2)	Performance Test Results.	No	Subpart UUU requires performance test results to be reported as part of the Notification of Compliance Status due 150 days after the compliance date.
§ 63.10(d)(3)	Opacity or VE Observations.	Yes.	
§ 63.10(d)(4)	Progress Reports	Yes.	
§ 63.10(d)(5)(i)	Startup, Shutdown, and Malfunction Reports.	Yes	Except that reports are not required if actions are consistent with the SSM plan, unless requested by permitting authority.
§ 63.10(d)(5)(ii)		Yes	Except that actions taken during a startup, shutdown, or malfunction that are not consistent with the plan do not need to be reported within 2 and 7 days of commencing and completing the action, respectively, but must be included in the next periodic report.
§ 63.10(e)(1)-(2)	Additional CMS Reports	Yes	Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or SO ₂ limits. Reports of performance evaluations must be submitted in Notification of Compliance Status.
§ 63.10(e)(3)	Excess Emissions/CMS Performance Reports.	No	Subpart UUU specifies the applicable requirements.
§ 63.10(e)(4)	COMS Data Reports	Yes.	
§ 63.10(f)	Recordkeeping/Reporting Waiver.	Yes.	
§ 63.11	Control Device Requirements.	Yes	Applicable to flares.
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by Reference.	Yes.	
§ 63.15	Available of Information	Yes.	

[70 FR 6966, Feb. 9, 2005]

APPENDIX A TO SUBPART UUU OF PART 63—DETERMINATION OF METAL CONCENTRATION ON CATALYST PARTICLES (INSTRUMENTAL ANALYZER PROCEDURE)

1.0 Scope and Application.

1.1 Analytes. The analytes for which this method is applicable include any elements

with an atomic number between 11 (sodium) and 92 (uranium), inclusive. Specific analytes for which this method was developed include:

Analyte	CAS No.	Minimum detectable limit
Nickel compounds	7440-02-0	<2 % of span.
Total chlorides	16887-00-6	<2 % of span.

1.2 **Applicability.** This method is applicable to the determination of analyte concentrations on catalyst particles. This method is applicable for catalyst particles obtained from the fluid catalytic cracking unit (FCCU) regenerator (*i.e.*, equilibrium catalyst), from air pollution control systems operated for the FCCU catalyst regenerator vent (FCCU fines), from catalytic reforming units (CRU), and other processes as specified within an applicable regulation. This method is applicable only when specified within the regulation.

1.3 **Data Quality Objectives.** Adherence to the requirements of this method will enhance the quality of the data obtained from the analytical method.

2.0 *Summary of Method.*

2.1 A representative sample of catalyst particles is collected, prepared, and analyzed for analyte concentration using either energy or wavelength dispersive X-ray fluorescent (XRF) spectrometry instrumental analyzers. In both types of XRF spectrometers, the instrument irradiates the sample with high energy (primary) x-rays and the elements in the sample absorb the x-rays and then re-emit secondary (fluorescent) x-rays of characteristic wavelengths for each element present. In energy dispersive XRF spectrometers, all secondary x-rays (of all wavelengths) enter the detector at once. The detector registers an electric current having a height proportional to the photon energy, and these pulses are then separated electronically, using a pulse analyzer. In wavelength dispersive XRF spectrometers, the secondary x-rays are dispersed spatially by crystal diffraction on the basis of wavelength. The crystal and detector are made to synchronously rotate and the detector then receives only one wavelength at a time. The intensity of the x-rays emitted by each element is proportional to its concentration, after correcting for matrix effects. For nickel compounds and total chlorides, the XRF instrument response is expected to be linear to analyte concentration. Performance specifications and test procedures are provided to ensure reliable data.

3.0 *Definitions.*

3.1 **Measurement System.** The total equipment required for the determination of analyte concentration. The measurement system consists of the following major subsystems:

3.1.1 **Sample Preparation.** That portion of a system used for one or more of the following: sample acquisition, sample transport, sample conditioning, or sample preparation prior to introducing the sample into the analyzer.

3.1.2 **Analyzer.** That portion of the system that senses the analyte to be measured and

generates an output proportional to its concentration.

3.1.3 **Data Recorder.** A digital recorder or personal computer used for recording measurement data from the analyzer output.

3.2 **Span.** The upper limit of the gas concentration measurement range displayed on the data recorder.

3.3 **Calibration Standards.** Prepared catalyst samples or other samples of known analyte concentrations used to calibrate the analyzer and to assess calibration drift.

3.4 **Energy Calibration Standard.** Calibration standard, generally provided by the XRF instrument manufacturer, used for assuring accuracy of the energy scale.

3.5 **Accuracy Assessment Standard.** Prepared catalyst sample or other sample of known analyte concentrations used to assess analyzer accuracy error.

3.6 **Zero Drift.** The difference in the measurement system output reading from the initial value for zero concentration level calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.7 **Calibration Drift.** The difference in the measurement system output reading from the initial value for the mid-range calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.8 **Spectral Interferences.** Analytical interferences and excessive biases caused by elemental peak overlap, escape peak, and sum peak interferences between elements in the samples.

3.9 **Calibration Curve.** A graph or other systematic method of establishing the relationship between the analyzer response and the actual analyte concentration introduced to the analyzer.

3.10 **Analyzer Accuracy Error.** The difference in the measurement system output reading and the ideal value for the accuracy assessment standard.

4.0 *Interferences.*

4.1 **Spectral interferences** with analyte line intensity determination are accounted for within the method program. No action is required by the XRF operator once these interferences have been addressed within the method.

4.2 **The X-ray production efficiency** is affected by particle size for the very lightest elements. However, particulate matter (PM) 2.5 particle size effects are substantially < 1 percent for most elements. The calibration standards should be prepared with material of similar particle size or be processed (ground) to produce material of similar particle size as the catalyst samples to be analyzed. No additional correction for particle size is performed. Alternatively, the sample can be fused in order to eliminate any potential particle size effects.

5.0 Safety.

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 X-ray Exposure. The XRF uses X-rays; XRF operators should follow instrument manufacturer's guidelines to protect from accidental exposure to X-rays when the instrument is in operation.

5.3 Beryllium Window. In most XRF units, a beryllium (Be) window is present to separate the sample chamber from the X-ray tube and detector. The window is very fragile and brittle. Do not allow sample or debris to fall onto the window, and avoid using compressed air to clean the window because it will cause the window to rupture. If the window should rupture, note that Be metal is poisonous. Use extreme caution when collecting pieces of Be and consult the instrument manufacturer for advice on cleanup of the broken window and replacement.

6.0 Equipment and Supplies.

6.1 Measurement System. Use any measurement system that meets the specifications of this method listed in section 13. The typical components of the measurement system are described below.

6.1.1 Sample Mixer/Mill. Stainless steel, or equivalent to grind/mix catalyst and binders, if used, to produce uniform particle samples.

6.1.2 Sample Press/Fluxer. Stainless steel, or equivalent to produce pellets of sufficient size to fill analyzer sample window, or alternatively, a fusion device capable of preparing a fused disk of sufficient size to fill analyzer sample window.

6.1.3 Analytical Balance. ± 0.0001 gram accuracy for weighing prepared samples (pellets).

6.1.4 Analyzer. An XRF spectrometer to determine the analyte concentration in the prepared sample. The analyzer must meet the applicable performance specifications in section 13.

6.1.5 Data Recorder. A digital recorder or personal computer for recording measurement data. The data recorder resolution (*i.e.*, readability) must be 0.5 percent of span. Alternatively, a digital or analog meter having a resolution of 0.5 percent of span may be used to obtain the analyzer responses and the readings may be recorded manually.

7.0 Reagents and Standards.

7.1 Calibration Standards. The calibration standards for the analyzer must be prepared catalyst samples or other material of similar

particle size and matrix as the catalyst samples to be tested that have known concentrations of the analytes of interest. Preparation (grinding/milling/fusion) of the calibration standards should follow the same processes used to prepare the catalyst samples to be tested. The calibration standards values must be established as the average of a minimum of three analyses using an approved EPA or ASTM method with instrument analyzer calibrations traceable to the U.S. National Institute of Standards and Technology (NIST), if available. The maximum percent deviation of the triplicate calibration standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). If the calibration analyses do not meet this criteria, the calibration standards must be re-analyzed. If unacceptable variability persists, new calibration standards must be prepared. Approved methods for the calibration standard analyses include, but are not limited to, EPA Methods 6010B, 6020, 7520, or 7521 of SW-846.¹ Use a minimum of four calibration standards as specified below (see Figure 1):

7.1.1 High-Range Calibration Standard. Concentration equivalent to 80 to 100 percent of the span. The concentration of the high-range calibration standard should exceed the maximum concentration anticipated in the catalyst samples.

7.1.2 Mid-Range Calibration Standard. Concentration equivalent to 40 to 60 percent of the span.

7.1.3 Low-Range Calibration Standard. Concentration equivalent to 1 to 20 percent of the span. The concentration of the low-range calibration standard should be selected so that it is less than either one-fourth of the applicable concentration limit or of the lowest concentration anticipated in the catalyst samples.

7.1.4 Zero Calibration Standard. Concentration of less than 0.25 percent of the span.

7.2 Accuracy Assessment Standard. Prepare an accuracy assessment standard and determine the ideal value for the accuracy assessment standard following the same procedures used to prepare and analyze the calibration standards as described in section 7.1. The maximum percent deviation of the triplicate accuracy assessment standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). The concentration equivalent of the accuracy assessment standard must be between 20 and 80 percent of the span.

7.3 Energy Calibration Standard. Generally, the energy calibration standard will be provided by the XRF instrument manufacturer for energy dispersive spectrometers. Energy calibration is performed using the manufacturer's recommended calibration standard and involves measurement of a specific energy line (based on the metal in the

energy calibration standard). This is generally an automated procedure used to assure the accuracy of the energy scale. This calibration standard may not be applicable to all models of XRF spectrometers (particularly wavelength dispersive XRF spectrometers).

8.0 Sample Collection, Preservation, Transport, and Storage. [Reserved]

9.0 Quality Control.

9.1 Energy Calibration. For energy dispersive spectrometers, conduct the energy calibration by analyzing the energy calibration standard provided by the manufacturer. The energy calibration involves measurement of a specific energy line (based on the metal in the energy calibration standard) and then determination of the difference between the measured peak energy value and the ideal value. This analysis, if applicable, should be performed daily prior to any sample analyses to check the instrument's energy scale. This is generally an automated procedure and assures the accuracy of the energy scale. If the energy scale calibration process is not automated, follow the manufacturer's procedures to manually adjust the instrument, as necessary.

9.2 Zero Drift Test. Conduct the zero drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the zero calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.3 Calibration Drift Test. Conduct the calibration drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the mid-range calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.4 Analyzer Accuracy Test. Conduct the analyzer accuracy test by analyzing the accuracy assessment standard and comparing the value output by the measurement system with the ideal value for the accuracy assessment standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

10.0 Calibration and Standardization.

10.1 Perform the initial calibration and set-up following the instrument manufacturer's

instructions. These procedures should include, at a minimum, the major steps listed in sections 10.2 and 10.3. Subsequent calibrations are to be performed when either a quality assurance/quality control (QA/QC) limit listed in section 13 is exceeded or when there is a change in the excitation conditions, such as a change in the tube, detector, X-ray filters, or signal processor. Calibrations are typically valid for 6 months to 1 year.

10.2 Instrument Calibration. Calibration is performed initially with calibration standards of similar matrix and binders, if used, as the samples to be analyzed (see Figure 1).

10.3 Reference Peak Spectra. Acquisition of reference spectra is required only during the initial calibration. As long as no processing methods have changed, these peak shape references remain valid. This procedure consists of placing the standards in the instrument and acquiring individual elemental spectra that are stored in the method file with each of the analytical conditions. These reference spectra are used in the standard deconvolution of the unknown spectra.

11.0 Analytical Procedure.

11.1 Sample Preparation. Prepare catalyst samples using the same procedure used to prepare the calibration standards. Measure and record the weight of sample used. Measure and record the amount of binder, if any, used. Pellets or films must be of sufficient size to cover the analyzer sample window.

11.2 Sample Analyses. Place the prepared catalyst samples into the analyzer. Follow the manufacturer's instructions for analyzing the samples.

11.3 Record and Store Data. Use a digital recorder or personal computer to record and store results for each sample. Record any mechanical or software problems encountered during the analysis.

12.0 Data Analysis and Calculations.

Carry out the following calculations, retaining at least one extra significant figure beyond that of the acquired data. Round off figures after final calculation.

12.1 Drift. Calculate the zero and calibration drift for the tests described in sections 9.2 and 9.3 (see also Figure 2) as follows:

$$\text{QC Value} = \frac{\text{CurrentAnalyzerCal. Response} - \text{InitialCal. Response}}{\text{Span}} \times 100 \quad (\text{Eq. A-1})$$

Where:

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

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InitialCal.Response = Initial instrument response for calibration standard;
QC Value = QC metric (zero drift or calibration drift), percent of span;

Span = Span of the monitoring system.

12.2 Analyzer Accuracy. Calculate the analyzer accuracy error for the tests described in section 9.4 (see also Figure 2) as follows:

$$\text{Accuracy Value} = \frac{\text{CurrentAnalyzerCal. Response} - \text{IdealCal. Response}}{\text{IdealCal. Response}} \times 100 \quad (\text{Eq. A-2})$$

Where:

Accuracy Value = Percent difference of instrument response to the ideal response for the accuracy assessment standard;

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

IdealCal.Response = Ideal instrument response for the accuracy assessment standard.

13.0 Method Performance.

13.1 Analytical Range. The analytical range is determined by the instrument design. For this method, a portion of the analytical range is selected by choosing the span of the monitoring system. The span of the monitoring system must be selected such that it encompasses the range of concentrations anticipated to occur in the catalyst sample. If applicable, the span must be selected such that the analyte concentration equivalent to the emission standard is not less than 30 percent of the span. If the measured analyte concentration exceeds the concentration of the high-range calibration standard, the sample analysis is considered invalid. Additionally, if the measured analyte concentration is less than the concentration of the low-range calibration standard but above the detectable limit, the sample analysis results must be flagged with

a footnote stating, in effect, that the analyte was detected but that the reported concentration is below the lower quantitation limit.

13.2 Minimum Detectable Limit. The minimum detectable limit depends on the signal-to-noise ratio of the measurement system. For a well-designed system, the minimum detectable limit should be less than 2 percent of the span.

13.3 Zero Drift. Less than ± 2 percent of the span.

13.4 Calibration Drift. Less than ± 5 percent of the span.

13.5 Analyzer Accuracy Error. Less than ± 10 percent.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 References.

1. U.S. Environmental Protection Agency. 1998. Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. EPA Publication No. SW-846, Revision 5 (April 1998). Office of Solid Waste, Washington, DC.

18.0 Tables, Diagrams, Flowcharts, and Validation Data.

Date:					
Analytic Method Used:					
	Zero ^a	Low-Range ^b	Mid-Range ^c	High-Range ^d	Accuracy Std ^e
Sample Run:					
1.					
2.					
3.					
Average.					
Maximum Percent Deviation.					

^a Average must be less than 0.25 percent of span.

^b Average must be 1 to 20 percent of span.

^c Average must be 40 to 60 percent of span.

^d Average must be 80 to 100 percent of span.

^e Average must be 20 to 80 percent of span.

Figure 1. Data Recording Sheet for Analysis of Calibration Samples.

Source Identification:

Run Number:
Test Personnel:
Span:
Date:

	Initial calibration response	Current analyzer calibration response	Drift (percent of span)
Zero Standard.			
Mid-range Standard.			
	Ideal calibration response	Current analyzer calibration response	Accuracy error (percent of ideal)
Accuracy Standard.			

Figure 2. Data Recording Sheet for System Calibration Drift Data.

[70 FR 6970, Feb. 9, 2005]

Subpart VVV—National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works

SOURCE: 64 FR 57579, Oct. 26, 1999, unless otherwise noted.

APPLICABILITY

§ 63.1580 Am I subject to this subpart?

(a) You are subject to this subpart if the following are all true:

(1) You own or operate a publicly owned treatment works (POTW) that includes an affected source (§ 63.1595);

(2) The affected source is located at a POTW which is a major source of HAP emissions, or at any industrial POTW regardless of whether or not it is a major source of HAP; and

(3) Your POTW is required to develop and implement a pretreatment program as defined by 40 CFR 403.8 (for a POTW owned or operated by a municipality, State, or intermunicipal or interstate agency), or your POTW would meet the general criteria for development and implementation of a pretreatment program (for a POTW owned or operated by a department, agency, or instrumentality of the Federal government).

(b) If your existing POTW treatment plant is not located at a major source as of October 26, 1999, but thereafter becomes a major source for any reason other than reconstruction, then, for the purpose of this subpart, your POTW treatment plant would be considered an existing source. Note to Paragraph (b): See § 63.2 of the national emission standards for hazardous air

pollutants (NESHAP) General Provisions in subpart A of this part for the definitions of major source and area source.

(c) If you reconstruct your POTW treatment plant, then the requirements for a new or reconstructed POTW treatment plant, as defined in § 63.1595, apply.

[67 FR 64745, Oct. 21, 2002]

§ 63.1581 Does the subpart distinguish between different types of POTW treatment plants?

Yes, POTW treatment plants are divided into two subcategories. A POTW treatment plant which does not meet the characteristics of an industrial POTW treatment plant belongs in the non-industrial POTW treatment plant subcategory as defined in § 63.1595.

INDUSTRIAL POTW TREATMENT PLANT DESCRIPTION AND REQUIREMENTS

§ 63.1582 What are the characteristics of an industrial POTW treatment plant?

(a) Your POTW is an industrial POTW treatment plant if an industrial discharger complies with its NESHAP by using the treatment and controls located at your POTW. Your POTW accepts the regulated waste stream and provides treatment and controls as an agent for the industrial discharger. Industrial POTW treatment plant is defined in § 63.1595.

(b) If, in the future, an industrial discharger begins complying with its NESHAP by using the treatment and controls at your POTW, then on the date that the industrial discharger certifies compliance, your POTW treatment plant will be considered an industrial POTW treatment plant.

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

**Appendix N Subpart Db - Standards of Performance for Industrial-Commercial-Institutional
Steam Generating Units**

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

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Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[44 FR 33613, June 11, 1979, as amended at 63 FR 49454, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999. Redesignated and amended at 70 FR 28653, 28656, May 18, 2005, and further redesignated and amended at 70 FR 51268, 51269, Aug. 30, 2005]

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in § 60.45Da or § 60.46Da shall provide notifications in accordance with § 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of § 60.7(f).

[70 FR 28656, May 18, 2005. Redesignated and amended at 70 FR 51268, 51269, Aug. 30, 2005]

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the particulate matter and nitrogen oxides standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than

73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the particulate matter and nitrogen oxides standards under this subpart and to the sulfur dioxide standards under subpart D (§ 60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the nitrogen oxides standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the nitrogen oxides standards under this subpart and the particulate matter and sulfur dioxide standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities which also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under subpart J (§ 60.104).

(d) Affected facilities which also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the nitrogen oxides and particulate matter standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; § 60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing TRS as defined under § 60.281 is not considered a modification under § 60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State.

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- (1) Section 60.44b(f).
- (2) Section 60.44b(g).
- (3) Section 60.49b(a)(4).

(h) Affected facilities which meet the applicability requirements under subpart Eb (Standards of performance for municipal waste combustors; § 60.50b) are not subject to this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, § 60.40).

(k) Any facility covered by subpart Eb or subpart AAAA of this part is not covered by this subpart.

(l) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

[52 FR 47842, Dec. 16, 1987, as amended at 63 FR 49454, Sept. 16, 1998; 65 FR 61752, Oct. 17, 2000; 71 FR 9881, Feb. 27, 2006; 71 FR 33400, June 9, 2006]

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.42b(a), § 60.43b(a), or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a

calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants means industrial plants which are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a heat recovery steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrosulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, 89, 90, 92, 96, or 98, Standard Specifications for Fuel Oils (incorporated by reference—see § 60.17).

Dry flue gas desulfurization technology means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or

series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m³ (70,000 Btu/hour-ft³).

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388-77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see § 60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m³ (70,000 Btu/hour-ft³) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount

of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-82, 86, 87, 91, or 97, "Standard Specification for Liquid Petroleum Gases" (IBR—see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical sulfur dioxide emissions (ng/J, lb/million Btu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants which are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired

in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units.

Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (IBR—see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil for units constructed, reconstructed, or modified on or before February 28, 2005, means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a sulfur dioxide control system

that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter or sulfur dioxide.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51819, Dec. 13, 1989; 65 FR 61752, Oct. 17, 2000; 66 FR 49834, Oct. 1, 2001; 71 FR 9831, Feb. 27, 2006]

§ 60.42b. Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), (d), (j), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential sulfur dioxide emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = (K_a H_a + K_b H_b) / (H_a + H_b)$$

where:

E_s is the sulfur dioxide emission limit, in ng/J or lb/million Btu heat input,
 K_a is 520 ng/J (or 1.2 lb/million Btu),
 K_b is 340 ng/J (or 0.80 lb/million Btu),
 H_a is the heat input from the combustion of coal, in J (million Btu),

H_b is the heat input from the combustion of oil, in J (million Btu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat input to the affected facility from exhaust gases from another source, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential sulfur dioxide emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of sulfur dioxide emissions, shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 50 percent of the potential sulfur dioxide emission rate (50 percent reduction) and that contain sulfur dioxide in excess of the emission limit determined according to the following formula:

$$E_s = (K_c H_c + K_d H_d) / (H_c + H_d)$$

where:

E_s is the sulfur dioxide emission limit, expressed in ng/J (lb/million Btu) heat input,
 K_c is 260 ng/J (0.60 lb/million Btu),
 K_d is 170 ng/J (0.40 lb/million Btu),
 H_c is the heat input from the combustion of coal, J (million Btu),

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H_L is the heat input from the combustion of oil, J (million Btu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input to the affected facility from exhaust gases from another source, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/million Btu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4).

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a Federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat input to the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat input to the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with any other gaseous fuels.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements

under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a Federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section, the sulfur dioxide emission limits and percent reduction requirements under this section apply at all times, including periods of start-up, shutdown, and malfunction.

(h) Reductions in the potential sulfur dioxide emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential sulfur dioxide emissions and

(2) Emissions from the pretreated fuel (without combustion or post combustion sulfur dioxide control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the sulfur dioxide control system is not being operated because of malfunction or maintenance of the sulfur dioxide control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in § 60.45b(c) or § 60.45b(d), and following the monitoring procedures as described in § 60.47b(a) or § 60.47b(b) to determine sulfur dioxide emission rate or fuel oil sulfur content; or (2) maintaining fuel receipts as described in § 60.49b(r).

(k) On or after the date on which the initial performance test is completed or is required to be completed under

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§ 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction or reconstruction after February 28, 2005, and that combusts coal, oil, gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential sulfur dioxide emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input, except as provided in paragraphs (k)(1) or (k)(2). Affected facilities subject to this paragraph are also subject to paragraphs (e) through (g) of this section.

(1) Units firing only oil that contains no more than 0.3 weight percent sulfur or any individual fuel with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from all other sulfur dioxide emission limits in this paragraph.

(2) Units that are located in a non-continental area and that combust coal or oil shall not discharge any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 230 ng/J (0.54 lb/MMBtu) heat input if the affected facility combusts oil.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51819, Dec. 18, 1989; 65 FR 61752, Oct. 17, 2000; 71 FR 9981, Feb. 27, 2006]

§ 60.43b Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility which combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/million Btu) heat input,

(i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/million Btu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(b) On and after the date on which the performance test is completed or required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 43 ng/J (0.10 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input,

(i) If the affected facility combusts only municipal-type solid waste, or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/million Btu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) for municipal-type solid waste, or municipal-type solid waste and other fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, but before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type

solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum design heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h)(1) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5).

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels,

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or a mixture of these fuels with any other fuels, and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur or other liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less is not subject to the PM or opacity limits in this section.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 61819, Dec. 18, 1989; 65 FR 61752, Oct. 17, 2000; 71 FR 9882, Feb. 27, 2006]

§ 60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO₂) in excess of the following emission limits:

Fuel/Steam generating unit type	Nitrogen oxide emission limits ng/J (lb/million Btu) (expressed as NO ₂) heat input
(1) Natural gas and distillate oil, except (4):	
(i) Low heat release rate	43 (0.10)
(ii) High heat release rate	86 (0.20)
(2) Residual oil:	
(i) Low heat release rate	130 (0.30)
(ii) High heat release rate	170 (0.40)
(3) Coal:	
(i) Mass-feed stoker	210 (0.50)
(ii) Spreader stoker and fluidized bed combustion	260 (0.60)
(iii) Pulverized coal	300 (0.70)
(iv) Lignite, except (v)	260 (0.60)
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340 (0.80)
(vi) Coal-derived synthetic fuels	210 (0.50)
(4) Duct burner used in a combined cycle system:	
(i) Natural gas and distillate oil	86 (0.20)
(ii) Residual oil	170 (0.40)

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of a limit determined by the use of the following formula:

$$E_n = [(EL_{go} H_{go}) + (EL_{ro} H_{ro}) + (EL_c H_c)] / (H_{go} + H_{ro} + H_c)$$

where:

E_n is the nitrogen oxides emission limit (expressed as NO₂), ng/J (lb/million Btu)

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EL_{go} is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/million Btu)

H_{go} is the heat input from combustion of natural gas or distillate oil.

EL_{ro} is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil.

H_{ro} is the heat input from combustion of residual oil.

EL_c is the appropriate emission limit from paragraph (a)(3) for combustion of coal, and

H_c is the heat input from combustion of coal.

(c) Except as provided under paragraph (1) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of 130 ng/J (0.30 lb/million Btu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility

to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (1) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = [(EL_{go} H_{go}) + (EL_{ro} H_{ro}) + (EL_c H_c)] / (H_{go} + H_{ro} + H_c)$$

where:

E_n is the nitrogen oxides emission limit (expressed as NO_x), ng/J (lb/million Btu)

EL_{go} is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/million Btu).

H_{go} is the heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, ng/J (lb/million Btu).

EL_{ro} is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/million Btu)

H_{ro} is the heat input from combustion of residual oil and/or liquid byproduct/waste.

EL_c is the appropriate emission limit from paragraph (a)(3) for combustion of coal, and

H_c is the heat input from combustion of coal.

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a nitrogen oxides emission limit which shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as nitrogen oxides emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the

emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific nitrogen oxides emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific nitrogen oxides emission limit will be established at the nitrogen oxides emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing nitrogen oxides emissions.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the nitrogen oxides emission limit which applies specifically to that affected facility. The petition

must include sufficient and appropriate data, as determined by the Administrator, on nitrogen oxides emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the nitrogen oxides emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the nitrogen oxides emission limits of this section. The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).)

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

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(3) Are subject to a Federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil and a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j) (1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 million Btu/hour) or less, are not subject to the nitrogen oxides emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility which commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO₂) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J_i (0.20 lb/million Btu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = [(0.10 * H_{go}) + (0.20 * H_r)] / (H_{go} + H_r)$$

Where:

E_n is the NO_x emission limit, (lb/million Btu),

H_{go} is the heat input from combustion of natural gas or distillate oil, and

H_r is the heat input from combustion of any other fuel.

(3) After February 27, 2006, units may comply with an optional limit of 270

ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.46a (i)(1), and must monitor emissions according to § 60.47a(c)(1), (c)(2), (k), and (l).

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51825, Dec. 18, 1989; 63 FR 49454, Sept. 16, 1998; 66 FR 42610, Aug. 14, 2001; 71 FR 9882, Feb. 27, 2006]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The sulfur dioxide emission standards under § 60.42b apply at all times.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential sulfur dioxide emission rate (% P_s) and the sulfur dioxide emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over the first 30 consecutive operating days of the steam generating unit. Compliance with the sulfur dioxide standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal or only oil is combusted, the following procedures are used:

(i) The procedures in Method 19 are used to determine the hourly sulfur dioxide emission rate (E_h) and the 30-day average emission rate (E₃₀). The hourly averages used to compute the 30-day

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averages are obtained from the continuous emission monitoring system of § 60.47b (a) or (b).

(ii) The percent of potential sulfur dioxide emission rate (% P_s) emitted to the atmosphere is computed using the following formula:

$$\% P_s = 100 (1 - \% R_w / 100) (1 - \% R_r / 100)$$

where:

$\% R_w$ is the sulfur dioxide removal efficiency of the control device as determined by Method 19, in percent.

$\% R_r$ is the sulfur dioxide removal efficiency of fuel pretreatment as determined by Method 19, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly sulfur dioxide emission rate (E_{ho}^o) is used in Equation 19-19 of Method 19 to compute an adjusted 30-day average emission rate (E_{30}^o). The E_{ho}^o is computed using the following formula:

$$E_{ho}^o = [E_{ho} - E_w(1 - X_k)] / X_k$$

where:

E_{ho}^o is the adjusted hourly sulfur dioxide emission rate, ng/J (lb/million Btu).

E_{ho} is the hourly sulfur dioxide emission rate, ng/J (lb/million Btu).

E_w is the sulfur dioxide concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted.

X_k is the fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19.

(ii) To compute the percent of potential sulfur dioxide emission rate (% P_s), an adjusted % R_s (% R_s^o) is computed from the adjusted E_{ho}^o from paragraph (b)(3)(i) of this section and an adjusted average sulfur dioxide inlet rate (E_{ai}^o) using the following formula:

$$\% R_s^o = 100 (1.0 - E_{ho}^o / E_{ai}^o)$$

To compute E_{ai}^o , an adjusted hourly sulfur dioxide inlet rate (E_{hi}^o) is used. The E_{hi}^o is computed using the following formula:

$$E_{hi}^o = [E_{hi} - E_w(1 - X_k)] / X_k$$

where:

E_{ai}^o is the adjusted hourly sulfur dioxide inlet rate, ng/J (lb/million Btu).

E_{hi} is the hourly sulfur dioxide inlet rate, ng/J (lb/million Btu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that $X_k = 1.0$. Owners or operators of affected facilities who assume $X_k = 1.0$ shall

(i) Determine % P_s following the procedures in paragraph (c)(2) of this section, and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with sulfur dioxide emission limits under § 60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters E_w or X_k under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure sulfur dioxide emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19.

(d) Except as provided in paragraph (j), the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a continuous emission measurement system (CEMS) is used, or based on a daily average if Method 6B or fuel sampling and analysis procedures under Method 19 are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum

capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for sulfur dioxide for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for sulfur dioxide for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for sulfur dioxide are cal-

culated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid sulfur dioxide emissions data in calculating % P_s and E_{so} under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid sulfur dioxides emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating % P_s and E_{so} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the sulfur dioxide control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate % P_s or E_s under § 60.42b (a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) Units that burn only oil that contains no more than 0.3 weight percent sulfur or fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining records of fuel supplier certifications of sulfur content of the fuels burned.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 71 FR 9883, Feb. 27, 2006]

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The particulate matter emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction, and as specified in paragraphs (i) and (j) of this section. The nitrogen oxides emission standards under § 60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under § 60.43b shall be determined through

performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j).

(c) Compliance with the nitrogen oxides emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the particulate matter emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8 using the following procedures and reference methods:

(1) Method 3B is used for gas analysis when applying Method 5 or Method 17.

(2) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after a wet FGD system. Do not use Method 17 after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B is to be used only after wet FGD systems.

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160 ± 14 °C (320 ± 25 °F).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5, Method 5B or Method 17 by traversing

the duct at the same sampling location.

(6) For each run using Method 5, Method 5B or Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19.

(7) Method 9 is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for nitrogen oxides required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring nitrogen oxides under § 60.48(b).

(1) For the initial compliance test, nitrogen oxides from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the nitrogen oxides emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the nitrogen oxides emission standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes

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first, the owner or operator of an affected facility which has a heat input capacity greater than 73 MW (250 million Btu/hour) and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the nitrogen oxides standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity of 73 MW (250 million Btu/hour) or less and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the nitrogen oxides standards under §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, nitrogen oxides emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the nitrogen oxides emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility which combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of paragraph (iii) of this section apply and the provisions of paragraph (iv) of this section are inapplicable.

(f) To determine compliance with the emissions limits for NO_x required by §60.44b(a)(4) or §60.44b(1) for duct burners used in combined cycle systems, ei-

ther of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NO_x shall be computed using Equation of 1 this section:

$$E = E_{sg} + (H_g / H_b)(E_{sg} - E_g) \text{ (Eq. 1)}$$

Where:

E = emissions rate of NO_x from the duct burner, ng/J (lb/million Btu) heat input

E_{sg} = combined effluent emissions rate, in ng/J (lb/million Btu) heat input using appropriate F-Factor as described in Method 19

H_g = heat input rate to the combustion turbine, in Joules/hour (million Btu/hour)

H_b = heat input rate to the duct burner, in Joules/hour (million Btu/hour)

E_g = emissions rate from the combustion turbine, in ng/J (lb/million Btu) heat input calculated using appropriate F-Factor as described in Method 19

(ii) Method 7E of appendix A of this part shall be used to determine the NO_x concentrations. Method 3A or 3B of appendix A of this part shall be used to determine oxygen concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b (a)(4) or §60.44b(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the continuous emission monitoring system specified under §60.48b for measuring NO_x and oxygen and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_x emissions rate at the outlet from the steam generating unit shall constitute the NO_x emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or

§ 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (see IBR § 60.17(h)). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 million Btu/hour) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the nitrogen oxides emission standards under § 60.44b using Method 7, 7A, 7E, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the nitrogen oxides emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E, or other approved reference methods.

(i) Units burning only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining fuel supplier certifications of the sulfur content of the fuels burned.

(j) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 80.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial start-up of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the continuous monitoring system if the owner or operator was previously determining compliance by Method 5, 5B, or 17 performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for particulate matter emissions as required under § 60.8 of subpart A of this part. Compliance with the particulate matter emission limit shall be determined by using the continuous emission monitoring system specified in paragraph (j) of this section to measure particulate matter and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19, section 4.1.

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

(7) At a minimum, valid continuous monitoring system hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid continuous emission monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(7) of this section are not met.

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA reference Method 3, 3A, or 3B, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be per-

formed annually and Response Correlation Audits must be performed every 3 years.

(13) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 55 FR 18876, May 7, 1990; 65 FR 61752, Oct. 17, 2000; 66 FR 18553, Apr. 10, 2001; 71 FR 9883, Feb. 27, 2006]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b), (f), and (g) of this section, the owner or operator of an affected facility subject to the sulfur dioxide standards under § 60.42b shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for measuring sulfur dioxide concentrations and either oxygen (O_2) or carbon dioxide (CO_2) concentrations and shall record the output of the systems. The sulfur dioxide and either oxygen or carbon dioxide concentrations shall both be monitored at the inlet and outlet of the sulfur dioxide control device.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average sulfur dioxide emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average sulfur dioxide input rate, or

(2) Measuring sulfur dioxide according to Method 6B at the inlet or outlet to the sulfur dioxide control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three

paired runs of a suitable sulfur dioxide and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B, Method 6A, or a combination of Methods 6 and 3 or 3B or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily sulfur dioxide emission rate, E_d , shall be determined using the procedure described in Method 6A, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/million Btu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/million Btu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average sulfur dioxide emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average sulfur dioxide emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly sulfur dioxide emission rates are not

calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the sulfur dioxide CEMS at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential sulfur dioxide emissions of the fuel combusted, and the span value of the CEMS at the outlet to the sulfur dioxide control device is 50 percent of the maximum estimated hourly potential sulfur dioxide emissions of the fuel combusted.

(f) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(g) Units burning any fuel with a potential sulfur dioxide emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, Dec. 18, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990; 71 FR 9883, Feb. 27, 2006]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) The owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system, except as provided in paragraphs (j) and (k) of this section.

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(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a nitrogen oxides standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous

monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for nitrogen oxides is determined as follows:

Fuel	Span values for nitrogen oxides (PPM)
Natural gas	500
Oil	500
Coal	1,000
Mixtures	$500(x+y)+1,000z$

where:

x is the fraction of total heat input derived from natural gas.

y is the fraction of total heat input derived from oil, and

z is the fraction of total heat input derived from coal.

(3) All span values computed under paragraph (e)(2) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm.

(f) When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 million Btu/hour) or less, and which has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section, or

(2) Monitor steam generating unit operating conditions and predict nitrogen oxides emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, which is subject to the NO_x standards of § 60.44b(a)(4) or § 60.44b(1) is not required

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to install or operate a continuous emissions monitoring system to measure NO_x emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a continuous monitoring system for measuring nitrogen oxides emissions.

(j) Units that burn only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The continuous monitoring systems specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51825, Dec. 18, 1989; 63 FR 49455, Sept. 16, 1998; 66 FR 18553, Apr. 10, 2001; 71 FR 9884, Feb. 27, 2006]

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility,

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i),

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired, and,

(4) Notification that an emerging technology will be used for controlling emissions of sulfur dioxide. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the nitrogen oxides standard of § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under § 60.48b(g)(2) and the records to be maintained under § 60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and nitrogen oxides emission rates (i.e., ng/J or lbs/million Btu

heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas oxygen level);

(2) Include the data and information that the owner or operator used to identify the relationship between nitrogen oxides emission rates and these operating conditions;

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(j).

If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan.

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b (j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D3431-80, Test Method for Trace Nitrogen in Liquid Petroleum Hydro-

carbons (IBR-see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under § 60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The average hourly nitrogen oxides emission rates (expressed as NO₂) (ng/J or lb/million Btu heat input) measured or predicted.

(3) The 30-day average nitrogen oxides emission rates (ng/J or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days.

(4) Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system

that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h) (1) or (2) of this section is required to submit excess emission reports for any excess emissions which occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under § 60.43b(e) or to the operating parameter monitoring requirements under § 60.13(i)(1).

(2) Any affected facility that is subject to the nitrogen oxides standard of § 60.44b, and that

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less, or

(ii) Has a heat input capacity of 73 MW (250 million Btu/hour) or less and is required to monitor nitrogen oxides emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average nitrogen oxides emission rate, as determined under § 60.45b(e), which exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for nitrogen oxides under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the sulfur dioxide standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average sulfur dioxide emission rate (ng/J or lb/million Btu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent reduction in sulfur dioxide emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken.

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which sulfur dioxide or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3.

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(1) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and

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the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average sulfur dioxide emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which sulfur dioxide or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken.

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(6) Identification of times when hourly averages have been obtained based on manual sampling methods.

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(8) Description of any modifications to the CEMS which could affect the ability of the CEMS to comply with Performance Specification 2 or 3.

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(m) For each affected facility subject to the sulfur dioxide standards under § 60.42(b) for which the minimum amount of data required under § 60.47b(f) were not obtained during the reporting period, the following information is reported to the Adminis-

trator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates.

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19, section 7.

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19, section 7.

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19, section 7.

(n) If a percent removal efficiency by fuel pretreatment (i.e., % R_f) is used to determine the overall percent reduction (i.e., % R_o) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (i.e., % R_f) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period.

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit.

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 (appendix A) and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or

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(k) shall maintain records of the following information for each steam generating unit operating day:

- (1) Calendar date,
 - (2) The number of hours of operation, and
 - (3) A record of the hourly steam load.
- (q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

- (1) The annual capacity factor over the previous 12 months;
- (2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and
- (3) If the affected facility meets the criteria described in §60.44b(j), the results of any nitrogen oxides emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last nitrogen oxides emission test.

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period.

(s) Facility specific nitrogen oxides standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the

C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the nitrogen oxides emission limit is 289 ng/J (0.67 lb/million Btu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The nitrogen oxides emission limit shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in §60.46b(i).

(iii) The monitoring of the nitrogen oxides emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific nitrogen oxides standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

Air ratio control damper is defined as the part of the low nitrogen oxides burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the nitrogen oxides emission limit is 473 ng/J (1.1 lb/million Btu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The nitrogen oxides emission limit shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in § 60.46b.

(iii) The monitoring of the nitrogen oxides emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph applies only to the pharmaceutical manufacturing fa-

cility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low nitrogen oxide (NO_x) technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_x emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a stack test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO₂ and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day

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following the end of the reporting period.

(x) Facility-specific nitrogen oxides standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the nitrogen oxides emission limit is 215 ng/J (0.5 lb/million Btu).

(2) *Emission monitoring for nitrogen oxides.* (i) The nitrogen oxides emissions shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in § 60.46b.

(ii) The monitoring of the nitrogen oxides emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 60 FR 28062, May 30, 1995; 61 FR 14031, Mar. 29, 1996; 62 FR 52641, Oct. 8, 1997; 63 FR 49455, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999; 65 FR 13243, Mar. 13, 2000; 69 FR 40773, July 7, 2004]

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 56 FR 37683, Sept. 12, 1990, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not covered by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not covered by this subpart.

[56 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 71 FR 9884, Feb. 27, 2006]

Facility: Lion Oil Co.
Permit No.: 868-AOP-R5
AFIN: 70-00016

**Appendix O Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for
Stationary Reciprocating Internal Combustion Engines**

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

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

SOURCE: 57 FR 61992, Dec. 29, 1992, unless otherwise noted.

Subpart Z—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE with a site-rating of more than 500 brake horsepower located at a major source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.* A stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before Decem-

ber 19, 2002. A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* A stationary RICE is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(3) *Reconstructed stationary RICE.* A stationary RICE is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraph (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(d).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE; or

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE.

(2) A new or reconstructed stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(d) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) A stationary RICE which is an existing spark ignition 2 stroke lean burn (2SLB) stationary RICE, an existing spark ignition 4 stroke lean burn (4SLB) stationary RICE, an existing compression ignition (CI) stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE; or an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary.

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007.

(2) If you start up your new or reconstructed stationary RICE before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with this subpart within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

EMISSION AND OPERATING LIMITATIONS**§ 63.6600 What emission limitations and operating limitations must I meet?**

(a) If you own or operate an existing, new, or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a of this subpart and the operating limitations in Table 1b of this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB or 4SLB stationary RICE or a new or reconstructed CI stationary RICE located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a of this subpart and the operating limitations in Table 2b of this subpart which apply to you.

(c) If you own or operate: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, or an existing CI stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE, you do not need to comply with the emission limitations in Tables 1a and 2a of this subpart or operating limitations in Tables 1b and 2b of this subpart.

GENERAL COMPLIANCE REQUIREMENTS**§ 63.6605 What are my general requirements for complying with this subpart?**

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times, except during periods of startup, shutdown, and malfunction.

(b) If you must comply with emission limitations and operating limitations, you must operate and maintain your stationary RICE, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction.

TESTING AND INITIAL COMPLIANCE REQUIREMENTS**§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations?**

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

§ 63.6615

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

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§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements in § 63.7(e)(1) and under the specific conditions that this subpart specifies in Table 4. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

(c) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 63.7(e)(1).

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 1})$$

Where:

C_i = concentration of CO or formaldehyde at the control device inlet,

C_o = concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO₂). If pollutant concentrations are to be corrected to 15 percent oxygen and CO₂ concentration is measured in lieu of oxygen concentration measurement, a CO₂ correction factor is needed. Calculate the CO₂ correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \quad (\text{Eq. 2})$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \quad (\text{Eq. 3})$$

Where:

X_{co_2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 - 15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the NO_x and SO_2 gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \quad (\text{Eq. 4})$$

Where:

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accuracy in percentage of true value must be provided.

§ 63.6625 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO₂ at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks

in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO₂ concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in § 63.8.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

CONTINUOUS COMPLIANCE REQUIREMENTS

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must

monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously at all times that the stationary RICE is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b and Tables 2a and 2b of this subpart that apply to you according to methods specified in Table 6 of this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b and Tables 2a and 2b of this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with your startup, shutdown, and malfunction plan.

(d) Consistent with §§ 63.6(e) and 63.7(e)(1), deviations from the emission or operating limitations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administra-

tor's satisfaction that you were operating in accordance with the startup, shutdown, and malfunction plan. For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations.

Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR § 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 of this subpart that apply to you. If you own or operate an existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing emergency stationary RICE, an existing limited use emergency stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you do not need to comply with the requirements in Table 8 of this subpart. If you own or operate a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE, you do not need to comply with the requirements in Table 8 of this subpart, except for the initial notification requirements.

NOTIFICATIONS, REPORTS, AND RECORDS

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE on or after August 16, 2004, you must submit an Initial Notification not later than 120

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days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE).

(e) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 of this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 of this subpart that includes a performance test conducted according to the requirements in Table 4 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) The first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) Each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown, or malfunction during the reporting period, the compliance report must include the information in § 63.10(d)(5)(i).

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the

emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(3), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

(2) The records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form on-site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off-site for the remaining 3 years.

OTHER REQUIREMENTS AND INFORMATION

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 of this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate an existing 2SLB, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE, you do not need to comply with any of the requirements of the General Provisions. If you own or operate a new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE, you do not need to comply with the requirements in the General Provisions except for the initial notification requirements.

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should

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contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101-549, 104 Stat. 2399).

Compression ignition engine means any stationary RICE in which a high boil-

ing point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition, including diesel engines, dual-fuel engines, and engines that are not spark ignition.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart.

(4) Fails to conform to any provision of the applicable startup, shutdown, or malfunction plan, or to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO₂.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration

unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO₂.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the

potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. May be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_x) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_x, CO, and volatile organic compounds (VOC) into CO₂, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.*, remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or sur-

face unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude

oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition engine means a type of engine in which a compressed air/fuel mixture is ignited by a timed electric spark generated by a spark plug.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart P of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

TABLE 1A TO SUBPART ZZZZ OF PART 63—EMISSION LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SPARK IGNITION, 4SRB STATIONARY RICE

[As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for existing, new and reconstructed 4SRB stationary RICE at 100 percent load plus or minus 10 percent]

For each . . .	You must meet one of the following emission limitations . . .
1. 4SRB RICE	<p>a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007, or</p> <p>b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2.</p>

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TABLE 1B TO SUBPART ZZZZ OF PART
63—OPERATING LIMITATIONS FOR EX-
ISTING, NEW, AND RECONSTRUCTED
SPARK IGNITION, 4SRB STATIONARY
RICE

[As stated in §§ 63.6600, 63.6630 and 63.6640, you must comply with the following operating emission limitations for existing, new and reconstructed 4SRB stationary RICE]

For each . . .	You must meet the following emission limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O ₂ and using NSCR.	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than two inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O ₂ and not using NSCR.	Comply with any operating limitations approved by the Administrator.

TABLE 2A TO SUBPART ZZZZ OF PART
63—EMISSION LIMITATIONS FOR NEW
AND RECONSTRUCTED LEAN BURN
AND COMPRESSION IGNITION STA-
TIONARY RICE

[As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent]

For each . . .	You must meet the following emission limitation . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O ₂ . If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O ₂ until June 15, 2007.
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O ₂ .
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O ₂ .

TABLE 2B TO SUBPART ZZZZ OF PART
63—OPERATING LIMITATIONS FOR
NEW AND RECONSTRUCTED LEAN
BURN AND COMPRESSION IGNITION
STATIONARY RICE

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[As stated in §§ 63.6600, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE]

For each . . .	You must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than two inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst.	Comply with any operating limitations approved by the Administrator.

TABLE 3 TO SUBPART ZZZZ OF PART 63—
SUBSEQUENT PERFORMANCE TESTS

[As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements]

For each . . .	Complying with the requirement to . . .	You must . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE.	Reduce CO emissions and not using a CEMS.	Conduct subsequent performance tests semiannually. ¹
2. 4SRB stationary RICE with a brake horsepower ≥5,000.	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually. ¹
3. Stationary RICE (all stationary RICE subcategories and all brake horsepower ratings).	Limit the concentration of formaldehyde in the stationary RICE exhaust.	Conduct subsequent performance tests semiannually. ¹

¹ After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semi-annual performance tests.

TABLE 4 TO SUBPART ZZZZ OF PART 63—
REQUIREMENTS FOR PERFORMANCE
TESTS

[As stated in §§ 63.6610, 63.6620, and 63.6640, you must comply with the following requirements for performance tests]

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements
1. 2SLB and 4SLB stationary RICE and CI stationary RICE.	a. Reduce CO emissions.	i. Measure the O ₂ at the inlet and outlet of the control device; and ii. Measure the CO at the inlet and the outlet of the control device.	(1) Portable CO and O ₂ analyzer. (1) Portable CO and O ₂ analyzer.	(a) Using ASTM D6522-00 ¹ (incorporated by reference, see § 63.14). Measurements to determine O ₂ must be made at the same time as the measurements for CO concentration. (a) Using ASTM D6522-00 ¹ (incorporated by reference, see § 63.14). The CO concentration must be at 15 percent O ₂ , dry basis.

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[As stated in §§ 63.6610, 63.6620, and 63.6640, you must comply with the following requirements for performance tests]

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE.	a. Reduce formaldehyde emissions.	i. Select sampling port location and the number of traverse points; and ii. Measure O ₂ at the inlet and outlet of the control device; and iii. Measure moisture content at the inlet and outlet of the control device; and iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 1 or 1A of 40 CFR part 60 appendix A § 63.7(d)(1)(i). (1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A. (1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03. (1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03 ² , provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Sampling sites must be located at the inlet and outlet of the control device. (a) Measurements to determine O ₂ concentration must be made at the same time as the measurements for formaldehyde concentration. (a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration. (a) Formaldehyde concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde in the stationary RICE exhaust.	i. Select the sampling port location and the number of traverse points; and ii. Determine the O ₂ concentration of the stationary RICE exhaust at the sampling port location; and iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and iv. Measure formaldehyde at the exhaust of the stationary RICE.	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i). (1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A. (1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03. (1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03 ² , provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) If using a control device, the sampling site must be located at the outlet of the control device. (a) Measurements to determine O ₂ concentration must be made at the same time and location as the measurements for formaldehyde concentration. (a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration. (a) Formaldehyde concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

¹ You may also use Methods 3A and 10 as options to ASTM-D6522-00. You may obtain a copy of ASTM-D6522-00 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

² You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

TABLE 5 TO SUBPART ZZZZ OF PART 63—
INITIAL COMPLIANCE WITH EMISSION
LIMITATIONS AND OPERATING LIMITATIONS

[As stated in §§ 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following]

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE.	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS.	i. the average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. 2SLB and 4SLB stationary RICE and CI stationary RICE.	a. Reduce CO emissions and not using oxidation catalyst.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
3. 2SLB and 4SLB stationary RICE and CI stationary RICE.	a. Reduce CO emissions, and using a CEMS.	i. You have installed a CEMS to continuously monitor CO and either O ₂ or CO ₂ at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
4. 4SRB stationary RICE	a. Reduce formaldehyde emissions and using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
5. 4SRB stationary RICE	a. Reduce formaldehyde emissions and not using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and

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[As stated in §§ 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following]

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
6. Stationary RICE	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	<ul style="list-style-type: none"> iii. You have recorded the approved operating parameters (if any) during the initial performance test. i. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
7. Stationary RICE	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	<ul style="list-style-type: none"> i. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.

TABLE 6 TO SUBPART ZZZZ OF PART 63—
CONTINUOUS COMPLIANCE WITH
EMISSION LIMITATIONS AND OPER-
ATING LIMITATIONS

[As stated in § 63.6640, you must continuously comply with the emissions and operating limitations as required by the following]

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE.	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS.	<ul style="list-style-type: none"> i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved¹; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. 2SLB and 4SLB stationary RICE and CI stationary RICE.	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS.	<ul style="list-style-type: none"> i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved¹; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

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[As stated in § 63.6640, you must continuously comply with the emissions and operating limitations as required by the following]

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
3. 2SLB and 4SLB stationary RICE and CI stationary RICE.	a. Reduce CO emissions and using a CEMS.	iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. 4SRB stationary RICE	a. Reduce formaldehyde emissions and using NSCR.	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. 4SRB stationary RICE	a. Reduce formaldehyde emissions and not using NSCR.	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. 4SRB stationary RICE with a brake horsepower $\geq 5,000$.	Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved ¹ .
7. Stationary RICE	Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit ¹ ; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. Stationary RICE	Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit ¹ ; and

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[As stated in § 63.6640, you must continuously comply with the emissions and operating limitations as required by the following]

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

¹After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semi-annual performance tests.

TABLE 7 TO SUBPART ZZZZ OF PART 63—
REQUIREMENTS FOR REPORTS

[As stated in § 63.6650, you must comply with the following requirements for reports]

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.9(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.9(c)(7), the information in § 63.6650(e); or c. If you had a startup, shutdown or malfunction during the reporting period, the information in § 63.10(d)(5)(i).	i. Semiannually according to the requirements in § 63.6650(b). i. Semiannually according to the requirements in § 63.6650(b). i. Semiannually according to the requirements in § 63.6650(b).
2. An immediate startup, shutdown, and malfunction report if actions addressing the startup, shutdown, or malfunction were inconsistent with your startup, shutdown, or malfunction plan during the reporting period.	a. Actions taken for the event; and b. The information in § 63.10(d)(5)(ii).	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan. i. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authorities. (§ 63.10(d)(5)(ii))
3. Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. Annually, according to the requirements in § 63.6650. i. See item 3.a.i.

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[As stated in § 63.6650, you must comply with the following requirements for reports]

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	c. Any problems or errors suspected with the meters.	i. See item 3.a.i.

TABLE 8 TO SUBPART ZZZZ OF PART 63—
APPLICABILITY OF GENERAL PROVISIONS TO SUBPART ZZZZ

[As stated in § 63.6665, you must comply with the following applicable general provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions.	Yes.	Additional terms defined in § 63.6675.
§ 63.2	Definitions	Yes	
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention.	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	
§ 63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources.	Yes.	
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources.	Yes.	
§ 63.6(c)(1)–(2)	Compliance dates for existing sources.	Yes.	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(c)(3)–(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources.	Yes.	
§ 63.6(d)	[Reserved]		
§ 63.6(e)(1)	Operation and maintenance	Yes.	
§ 63.6(e)(2)	[Reserved]		
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan.	Yes.	
§ 63.6(f)(1)	Applicability of standards except during startup shutdown malfunction (SSM).	Yes.	
§ 63.6(f)(2)	Methods for determining compliance.	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)–(3)	Use of alternate standard	Yes.	Subpart ZZZZ contains performance test dates at § 63.6610.
§ 63.6(h)	Opacity and visible emission standards.	No	
§ 63.6(i)	Compliance extension procedures and criteria.	Yes.	
§ 63.6(j)	Presidential compliance exemption.	Yes.	
§ 63.7(a)(1)–(2)	Performance test dates	Yes	
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes.	
§ 63.7(b)(2)	Notification of rescheduling	Yes.	
§ 63.7(c)	Quality assurance/test plan	Yes.	
§ 63.7(d)	Testing facilities	Yes.	
§ 63.7(e)(1)	Conditions for conducting performance tests.	Yes.	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data.	Yes	
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA.	Yes.	
§ 63.7(f)	Alternative test method provisions.	Yes.	

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[As stated in § 63.6665, you must comply with the following applicable general provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting.	Yes.	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements.	Yes.	
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved]		Subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems.	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance.	Yes.	Subpart ZZZZ does not require COMS.
§ 63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan.	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements.	Yes.	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes.	Subpart ZZZZ does not require COMS.
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements.	Yes.	
§ 63.8(c)(5)	COMS minimum procedures	No.	
§ 63.8(c)(6)-(8)	CMS requirements	Yes.	
§ 63.8(d)	CMS quality control	Yes.	Except for § 63.8(e)(5)(ii), which applies to COMS.
§ 63.8(e)	CMS performance evaluation	Yes.	
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes.	
§ 63.8(f)(6)	Alternative to relative accuracy test.	Yes.	
§ 63.8(g)	Data reduction	Yes.	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements.	Yes.	
§ 63.9(b)(1)-(5)	Initial notifications	Yes.	
§ 63.9(c)	Request for compliance extension.	Yes.	
§ 63.9(d)	Notification of special compliance requirements for new sources.	Yes.	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(e)	Notification of performance test	Yes.	
§ 63.9(f)	Notification of visible emission (VE)/opacity test.	No.	
§ 63.9(g)(1)	Notification of performance evaluation.	Yes.	
§ 63.9(g)(2)	Notification of use of COMS data.	No.	Subpart ZZZZ does not contain opacity or VE standards. If alternative is in use.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded.	Yes.	
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes.	
§ 63.9(i)	Adjustment of submittal deadlines.	Yes.	
§ 63.9(j)	Change in previous information	Yes.	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
§ 63.10(a)	Administrative provisions for record-keeping/reporting.	Yes.	
§ 63.10(b)(1)	Record retention	Yes.	
§ 63.10(b)(2)(i)-(v)	Records related to SSM	Yes.	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	

[As stated in § 63.6065, you must comply with the following applicable general provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA.	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation.	Yes.	
§ 63.10(b)(3)	Records of applicability determination.	Yes.	
§ 63.10(c)	Additional records for sources using CEMS.	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results.	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations.	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports.	Yes.	
§ 63.10(e)(1) and (2)(i)	Additional CMS reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports.	Yes	Except that § 63.10(e)(3)(i)(C) is reserved.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting.	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

Subpart AAAAA—National Emission Standards for Hazardous Air Pollutants for Lime Manufacturing Plants

SOURCE: 69 FR 416, Jan. 5, 2004, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 63.7080 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (NESHAP) for lime manufacturing plants. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.7081 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a lime manufacturing plant (LMP) that is a major source, or that is located at, or is part of, a major source of hazardous air pollutant (HAP) emissions, unless the LMP is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, beet

sugar manufacturing plant, or only processes sludge containing calcium carbonate from water softening processes.

(1) An LMP is an establishment engaged in the manufacture of lime product (calcium oxide, calcium oxide with magnesium oxide, or dead burned dolomite) by calcination of limestone, dolomite, shells or other calcareous substances.

(2) A major source of HAP is a plant site that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year from all emission sources at the plant site.

(b) [Reserved]

§ 63.7082 What parts of my plant does this subpart cover?

(a) This subpart applies to each existing or new lime kiln(s) and their associated cooler(s), and processed stone handling (PSH) operations system(s) located at an LMP that is a major source.

CERTIFICATE OF SERVICE

I, Pam Owen, hereby certify that a copy of this permit has been mailed by first class mail to Lion Oil Company, 1000 McHenry Drive, El Dorado, AR, 71730, on this 1st day of October, 2007.

P. Owen / csa
Pam Owen, AAII, Air Division

