Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
(415) 771-6000

Final
Permit Evaluation
and
Statement of Basis
for
MAJOR FACILITY REVIEW PERMIT
Reopening – Revision 1
August 2004

for

Shell Martinez Refinery, Shell Oil Products US
Facility #A0011

Facility Address:
3485 Pacheco Blvd.
Martinez, CA 94553

Mailing Address:
P O Box 711
Martinez, CA 94553

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TABLE OF CONTENTS

Title V Statement of Basis

A. Background

This facility is subject to the Operating Permit requirements of Title V of the federal Clean Air Act, Part 70 of Volume 40 of the Code of Federal Regulations (CFR), and BAAQMD Regulation 2, Rule 6, Major Facility Review because it is a major facility as defined by BAAQMD Regulation 2-6-212. It is a major facility because it has the "potential to emit," as defined by BAAQMD Regulation 2-6-218, of more than 100 tons per year of a regulated air pollutant.

Major Facility Operating permits (Title V permits) must meet specifications contained in 40 CFR Part 70 as contained in BAAQMD Regulation 2, Rule 6. The permits must contain all applicable requirements (as defined in BAAQMD Regulation 2-6-202), monitoring requirements, recordkeeping requirements, and reporting requirements. The permit holders must submit reports of all monitoring at least every six months and compliance certifications at least every year.

In the Bay Area, state and District requirements are also applicable requirements and are included in the permit. These requirements can be federally enforceable or non-federally enforceable. All applicable requirements are contained in Sections I through VI of the permit.

The District issued the initial Title V permit to this facility on December 1, 2003. The District has reopened the permit to amend flare and Regulation 9-10 requirements and to correct errors. All changes to the permit will be clearly shown in "strikeout/underline" format. When the permit is finalized, the "strikeout/underline" format will be removed.

The District is soliciting public comment on the proposed revisions. The District is also soliciting comment on changes that were made between the version of the permits that were issued for public comment in July of 2003 and the final permits issued December 1, 2003. Though the District does not believe these changes were of such a magnitude as to render the issuance notice and comment process inadequate, these permits were the subject of considerable scrutiny, and so the District wishes to be as thorough as possible in allowing an opportunity for comment on all aspects of the final permits. The District will respond to comments received on these changes from draft to final. Any changes to the permit that result from comments received will be addressed in a future revision.

Regarding EPA's review of the final permits, EPA has indicated to the District that, because of the extent of changes made between proposal and final, it intends to conduct a new review of the refinery permits in their entirety. The District acknowledges that EPA has this authority and intends to respond appropriately to any issues EPA may raise in its review, whether or not those issues relate to the proposed revisions. EPA has informed the District that it intends to commence a 45-day review period on the entire content of each refinery Title V permit when it receives the version of the permit that is proposed for revision.

This statement of basis concerns only changes to the permit. A comprehensive statement of basis was prepared for the initial issuance of the permit and is considered to be the statement for basis for the entire permit. It is available on request.

B. Facility Description

The Shell Martinez Refinery consists of a petroleum refinery and chemical manufacturing complex. The refinery converts approximately 140,000 barrels of crude oil per day into many finished products, including liquefied petroleum gas, automotive gasoline, jet fuel, diesel, industrial fuel oils, asphalt and petroleum coke. The Lubricants Department also processes crude oil, approximately 16,000 barrels per day, into finished lubricating oils, sodium sulfonates and asphalt. The chemical plant manufactures several different specialty chemicals.

The Shell Martinez Refinery has been in operation since 1915. The light oil processing (LOP) units were added in the mid 1970's, and the Flexicoker and associated units were added in the mid 1980's. Several new "clean fuels" units were added in 1995, including the Delayed Coker unit.

Finished products from the refinery include Liquefied Petroleum gas (LPG), which is sold as Propane and used for home heating, cooking, recreational vehicles, etc. Automotive gasoline and diesel are marketed throughout California and Nevada and used to power cars, trucks, busses, boats and farm equipment. Heavier fuel oils are used for heating, in industrial steam boilers and utilities. Asphalt is used as a road mix material throughout the western United States and Canada. Lubricating oils include non-PCB electrical transformer oil, base stocks which are used to manufacture motor oils and extender oils which are used in rubber manufacturing processes. Sodium sulfonates are used as an emulsifying agent in detergents.

Through a variety of chemical reactions and physical changes, the Martinez Refinery manufactures finished petroleum products from crude oil. Oil Refining includes four basic processes, described below:

SEPARATION	Liquid hydrocarbons are separated into common boiling point fractions by distillation. The distillation process makes a "rough cut" of the crude oil, producing gases, light, medium and heavy boiling-range materials, and residuals. These cuts, or intermediate streams are then further processed by more sophisticated means.
CONVERSION	Cracking - This process breaks or cracks large hydrocarbon molecules into smaller ones. This is done by thermal or catalytic cracking.
	Reforming - This process uses high temperatures and catalysts to rearrange the chemical structure of a particular oil stream to improve its quality.
	Combining - This process chemically combines two or more hydrocarbon streams to produce a higher-grade

	product. Liquefied petroleum gas streams are combined in this manner to produce gasoline.
PURIFICATION	This process converts contaminants into an easily removable or acceptable form.
BLENDING	This process mixes combinations of hydrocarbon liquids to produce a final product.

A more detailed description of petroleum refinery processes and the resulting air emissions may be found in Chapter 5 of EPA's publication AP-42, Compilation of Air Pollutant Emission Factors. This document may be found at:

http://www.epa.gov/ttn/chief/ap42/ch05/

The principal sources of air emissions from refineries are:

- Combustion units (furnaces, boilers, and cogeneration facilities)
- FCC (Fluidized Catalytic Cracking)
- Storage tanks
- Fugitive emissions from pipe fittings, pumps, and compressors
- Sulfur plants
- Wastewater treatment facilities

Combustion unit emissions are generally controlled through the use of burner technology, steam injection, or selective catalytic reduction. Emissions from the FCCU are controlled through the use of improved catalyst regeneration, CO boilers, electrostatic precipitators, hydrotreating the feed, and use of catalysts to remove impurities. Storage tank emissions are controlled through the use of add on control and or fitting loss control. Fugitive emissions have been controlled through the use of inspection and maintenance frequencies. Sulfur plants are equipped with tail gas units to reduce emissions. Wastewater treatment facilities are controlled by covering units, gasketing covers, and add on controls such as, carbon canisters.

C. Permit Content

The legal and factual basis for the permit follows. The permit sections are described in the order that they are presented in the permit.

I. Standard Conditions

No change has been made to this section.

Changes made to permit in response to EPA's October 8, 2004 letter:

Recordkeeping for Multiple Compliance Options:

Some applicable requirements allow multiple compliance option. In some cases, the operator has chosen one specific option, and only that option is contained in the permit. Some requirements do not require the operator select a specific compliance method, and some operators have chosen to have more than one option incorporated into the permit. Standard permit condition I.J.4 has been added to the permit to ensure that the records necessary to determine compliance are kept, and the method for determining compliance is reported in the annually compliance certification.

Informational Permit Condition:

EPA has requested that the District make determinations regarding the applicability of certain requirements listed in Attachment 2 of the October 8, 2004 letter. In addition, EPA has also requested the addition of a permit condition requiring facilities to supply relevant information by January 5, 2005. In light of the above, standard permit conditions I.J.5 through I.J.9 have been added to the permit.

II. Equipment

Table II A - Permitted Sources

The capacities for S1771, S1772, S1778, and S4201 have been deleted because flares and cooling water towers are not limited by capacity due to operational use. The primary purpose of throughput limits is to serve as an indicator that a modification has occurred. Specifying throughput limits for flares which are used to handle emergency situations and cooling towers which are needed to cool processes would not necessarily serve as an indicator that a modification has occurred but only that the flare or cooling tower was required to handle a process that required its use. The capacity to S1507, S1509, S1512, S1765, S3000, S4190, S4191, S4192, and has also been deleted and a reference to Part 1 of Condition # 18618, Part 1 added in its place to eliminate unnecessary redundancy or confusion. Source throughputs are identified in Part 1 of Condition # 18618.

Information requested in EPA's October 8, 2004 letter:

Per EPA's request, the following table lists thermal oxidizers at the refinery that are contained in "Table II B - Abatement Devices" of the permit:

Thermal Oxidizer I.D.	Thermal Oxidizer Description
A100	Thermal oxidizer for marine vapor recovery system
A1501	Backup thermal oxidizer for sulfur plants 1 and 2
A1517	Primary thermal oxidizer for sulfur plants 1 and 2
A1518	Catalytic oxidizer for sulfur plant 3
A4181	Thermal oxidizer for sulfur plant 4

III. Generally Applicable Requirements

No change has been made to this section.

IV. Source-Specific Applicable Requirements

This section of the permit lists the applicable requirements that apply to permitted or significant sources. These applicable requirements are contained in tables that pertain to one or more sources that have the same requirements. The order of the requirements is:

- District Rules

- SIP Rules (if any) listed following the corresponding District Rules. SIP rules are District rules that have been approved by EPA into the California State Implementation Plan. SIP rules are “federally enforceable” and a “Y” (yes) indication will appear in the “Federally Enforceable” column. If the SIP rule is the current District rule, separate citation of the SIP rule is not necessary and the “Federally Enforceable” column will have a “Y” for “yes”. If the SIP rule is not the current District rule, the SIP rule or the necessary portions of the SIP rule are cited separately after the District rule. The SIP portions will be federally enforceable; the non-SIP versions will not be federally enforceable, unless EPA has approved them through another program.
- Other District requirements, such as the Manual of Procedures, as appropriate.
- Federal requirements (other than SIP provisions)
- BAAQMD permit conditions. The text of BAAQMD permit conditions is found in Section VI of the permit.
- Federal permit conditions. The text of Federal permit conditions, if any, is found in Section VI of the permit.

Section IV of the permit contains citations to all of the applicable requirements. The text of the requirements is found in the regulations, which are readily available on the District’s or EPA’s websites, or in the permit conditions, which are found in Section VI of the permit. All monitoring requirements are cited in Section IV. Section VII is a cross-reference between the limits and monitoring requirements. A discussion of monitoring is included in Section C.VII of this permit evaluation/statement of basis.

Applicability of Regulation 8-2 to emissions from flares: The District has determined that properly designed and operated flares achieve a VOC destruction efficiency exceeding 90%. Emissions from such a device are exempted from Regulation 8-2 by Regulation 8-1-110.3.

Proper design of refinery flares is presumed by the District based on its review of the history of installation and industry standards that are in place to assure proper operation.

Except for S-1771 Flare, proper operation is presumed if the flare is operated within its design capacity, if the BTU content of gases flared exceed 300 BTU/scf, and if a flame is present during flaring. District regulation 12-11 requires flow monitoring, gas composition analysis, and verification of the presence of flame during flaring events.   The Flexigas Flare, S-1771, burns low-BTU flexigas efficiently and cleanly because of the 1) composition of the flexigas and 2) lack of any other materials going to the flare (i.e. it burns only flexigas, which provides for flame stability,etc). The flexigas composition consists of a high hydrogen (~ 15%) and carbon monoxide (~20%) content. These compounds are found in flexigas at higher percentages than normally found in fuel gas. Compared to fuel gas, flexigas also has a much lower percentage of hydrocarbons. Flexigas is typically less than 1% hydrocarbons in composition, whereas refinery fuel gases range from 30-70% hydrocarbons. Also, hydrogen and carbon monoxide have very high reaction rate constants compared to the hydrocarbons typically found in fuel gas. The high reaction rate constants result in smokeless burning as the gas is combusted at all flow rates, including during times of flow rate increase.

Refinery flares are exempt from Regulation 8-2 during any flaring event where conditions ensure proper operation. The required monitoring provides assurance that the flares are operated properly.

In addition to the exemption contained in Regulation 8-1-110.3, flaring of gases from sources subject to other District rules are not subject to 8-2, because such sources are not "miscellaneous sources" (8-2-201). Thus emissions due to flaring of gases from sources subject to Regulation 10 (NSPS) or other Regulation 8 rules are not subject to 8-2.

Changes to this Section IV are primarily routine and include updating the applicable requirements tables to reflect changes to permit conditions as described in Section VI. Permit Conditions. However, in some cases applicable requirements have been added or removed at the request of Shell where there were errors or omissions in the initial permit. A discussion of these "non-routine" changes follows:

- 40 CFR 60 Subpart A has been deleted from Table IV-AXa for A101, A102 and A103. Table IV-CX for S4201 is correct (it is also not subject to 40 CFR 60 Subpart A). In accordance with 60.104(a)(1), all of these flares (A101, A102, A103, and S4201) are exempt from Subpart J to the extent they are only used for process upset/malfunction. Additionally, none of the flares are control devices for any NSPS or NESHAPS sources.

- S1772, the Hydrocarbon Flare, is also exempt from Subpart J to the extent it handles only process upset/malfunction gas. Because available information does not suggest it is being used in other ways, it should not be in the Table IV-BW with S1771. To fix this, S1772 was deleted from Table IV-BW and Regulation 6 and Condition 18618 parts (as applicable) were added to Table IV-BX (which has been renamed from BXb) for S1772. In addition, Table IV-BX has been expanded to include the sections of Table BXa, which has been deleted. In addition, the exemption to Subpart J was added and the applicable sections of Subpart A.

- The federal enforceability of the Regulation 9-10 based permit conditions (proposed and current in Condition # 18265 (Parts 1 through 21) have been correct to reflect that they are NOT federally enforceable because they are based on sections in Regulation 9-10, which haven't been approved in the State Implementation Plan.

Shell only has thermal oxidizers for their marine vessel loading berths (S2001- S2004). The marine loading is not subject to NESHAPS (40 CFR 63 Subpart Y). It is exempt from the MACT because of low emissions and exempt from the RACT because of low throughput. Therefore, there are no requirements for a minimum residence time.

The following tanks: S610-S613, S1133 and S1134, S1751-S1754, S1757, and S4334 are not affected sources subject to Subpart CC (63.640(d)). In accordance with 63.640(d)(5), no testing, monitoring, recordkeeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.

The facility commented that Regulation 6-305 should be removed as a source-specific applicable requirement for flares and other gas-fired only combustion devices. The District considers that this standard applies to all combustion sources.

SIP version of Regulation 9-1-313 was added to Table IV-AQ and IV-DV.

Part 8 under Condition # 18265 in Section IV Tables AY, AZ, and CS was deleted because it only applies to sources with CEM analyzers installed. Because these three tables only include sources without CEM analyzers, Part 8 has been removed. Part 16 only applies to S1800. As a result, this Part 16 has also been removed from Tables AY, AZ, and CS.

Parts 3, 4, 5, 6, 7, 9, 12, 16, 18, and 19 of Condition # 18265 apply only to sources without CEM analyzers. As a result, these parts have been deleted from Section IV Tables BA, BC, BD, BG, BL, and CU.

BAAQMD 6-305 was added as an applicable requirement for Flare 4201 (S4201).

Shell has asserted that the ETP-1 wastewater treatment train is not required to be managed in accordance with the control requirements specified by 40 CFR 61 Subpart FF (or the wastewater provisions of 40 CFR 63 Subpart CC). The District agrees. Accordingly, some minor changes to the Title V permit were in order.

Under 40 CFR 61 Subpart FF and the wastewater provisions of 40 CFR 63 Subpart CC, facilities have several available compliance options. The compliance option selected for the Shell Martinez Refinery, known as "6BQ", requires that most aqueous benzene containing waste be managed in controlled systems in accordance with the standards listed in 40 CFR 61 Subpart FF (an aqueous stream is one containing 10% or greater water on an annual average basis). All non-aqueous benzene waste streams must be managed and controlled in accordance with 40 CFR 61.342 (c)(1)The selected compliance option provides a six (6) megagram per year (Mg/yr) "allotment" for aqueous waste streams that are not managed in controlled systems. To comply with the 6BQ compliance option, Shell has segregated the "larger" benzene containing streams, including those managed in controlled systems. The remaining benzene containing aqueous waste streams, including those managed in ETP-1, are managed in uncontrolled systems and are subject to a facility-wide requirement to annually document that these streams contain less than six Mg/yr. This facility-wide requirement is cited in Table IV-DV for citation 61.342(e)(2). Although Shell currently manages ETP-1 in accordance with the control provisions of 40 CFR 61 Subpart FF, the regulations allow Shell to manage ETP-1 as an uncontrolled system under the "6BQ" compliance option. Therefore, in the Title V permit, these operations are being delisted from the standards listed in 40 CFR 61 Subpart FF and the wastewater provisions of 40 CFR 63 Subpart CC. As a result, their Title V permit has been changed in the following manner:

1. Requirements for 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC have been removed from Table IV-AV and Table VII-AM
2. Since only S5115 and S5116 are subject to the requirements in 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC, sources S2007 and S2008 have been moved from Table IV-CG and are currently listed under Table IV-CH. .

3. In similar fashion, Table VII-BS that previously listed S2007, S2008, S5115, and S5116 together has been renumbered to Tables VII-BSa (monitoring requirements for S5115 and S5116) and VII-BSb (monitoring requirements for S2007 and S2008).

4. In light of the above, the abatement device table as it relates to the above sources was modified to include and/or exclude references to 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC.

Subpart J

EPA commented that NSPS Subpart J, an EPA-promulgated standard, is applicable to thermal oxidizers at petroleum refineries. EPA notes that thermal oxidizers combust gas, and are therefore a "fuel gas combustion device," which is defined at 40 CFR § 60.102(g) to mean "any equipment, such as process heaters, boilers and flares used to combust fuel gas . . .." Although thermal oxidizers in most instances combust gas for no purpose other than abatement of the gas stream, and although gas combusted in a thermal oxidizer may or may not have heating value sufficient to serve as fuel gas for refinery processes, the NSPS J definition of fuel gas is clear in declaring a "fuel gas" to be "any gas which is generated at a petroleum refinery which is combusted." See 40 CFR § 60.101(d).

If EPA's comment is correct, then Subpart J would be incorporated into the Title V permit as an applicable requirement for thermal oxidizers A100, A1501, A1517, A1518, and A4181 and a schedule of compliance would be established addressing instances of non-compliance. Because incorporation of Subpart J for these units was not part of the Revision 1 proposal, and because the issue deserves consideration based after an opportunity comment by all interested parties, the District will address incorporation of Subpart J for these units in the next revision. In the mean time, no Title V permit shield is provided for A100, A-1518, and A4181, and so the Title V permit does not impact the applicability of Subpart J as a federal matter. Please note that if EPA's comment is correct, the permit shield for A1501 and A1517 that currently exists in Table IX A-4 in the Section IX "Permit Shield" of the permit is invalid, because the reason listed in the permit shield is not valid. Accordingly, the District encourages refineries with affected fuel gas combustion devices to be considering their compliance options even while the next revision is pending.

Changes made to permit in response to EPA's October 8, 2004 letter:

Facility (Flares):

EPA commented that NSPS Subpart A (40 CFR 60.1-60.19) should be incorporated into the permit when any NSPS is included as an applicable requirement. Because Subpart A is incorporated into every NSPS standard (unless otherwise specified), Subpart A applies to each facility that is subject to an NSPS. The District has assumed that incorporation of Subpart A is automatic with incorporation of any NSPS. Some District permits reflect this assumption by not specifically listing Subpart A as applicable. However, the District agrees with EPA that this should be clarified in the permit rather than assumed, and accordingly is adding specific reference to Subpart A. Not every section of Subpart A is relevant to every NSPS affected facility. Provisions of Subpart A that are not relevant at a facility may be disregarded.

To address Item 3 of attachment 3 to EPA's letter dated October 8, 2004, the requirements contained in 40 CFR 60, Subpart A, Section 60.11 (a) and (d), concerning good engineering practice have been added for the following abatement devices: A101 & A102 (in Table IV-AXa), A103 (in Table AXb), and S4201 (in Table CX). The remaining subsections, 60.11(b), (c), and (e), concern compliance with opacity standards in the New Source Performance Standards. Since these abatement devices are not subject to the opacity standards, they are not subject to these subsections.

Hydrogen Plant:
There are three hydrogen plants at Shell – sources S1445 (HP-1), S1774 (HP-2), and S4160 (HP-3). In response to an EPA comment seeking clarification on the applicability of Regulation 8, Rule 2 to emission vents at the above sources, Shell clarified that the deaerator vent and CO2 vent at both S1445 and S1774 vent directly to the atmosphere. The company also confirmed that a recent source test conducted by the District determined that the emissions at both of the above referenced hydrogen plants complied with the Regulation 8-2-301 limit. Shell clarified that S4160 does not have any CO emission points venting to the atmosphere. In light of the above, the Regulation 8-2-301 limit has been incorporated into Table IV-AL and the pertinent monitoring and testing requirements have been incorporated into Table VII-AE. Lastly, a new permit condition (# 21896) now requires Shell to conduct an annual source test at the deaerator vent and CO2 vent at S1445 and S1774 to demonstrate compliance with the Regulation 8-2-301 limit.

BAAQMD Regulation 8, Rule 10 "Process Vessel Depressurization":
The permit did not specify whether the requirement of Regulation 8, Rule 10 referred to the SIP approved version adopted on 7/20/83 or the new BAAQMD version adopted on 1/21/2004, which has not yet been SIP approved. Both versions must be included in the permit. All requirements of the SIP approved version are federally enforceable. The District has determined that additional monitoring is required to assure compliance with SIP Regulation 8-10-301.4. The monitoring required by BAAQMD Regulation 8-10-501 and 8-10-502 is adequate to determine compliance with SIP Regulation 8-10-301.4. These non-SIP regulations have therefore been flagged as federally enforceable.

In light of the above, 8-10-501 and 502 have been added as federally enforceable requirements to Tables IV-AL, AP, CZ, and DAa that list SIP 8-10-301 as an applicable requirement. In addition, 8-10-502 has been listed as the monitoring method for demonstrating compliance with SIP 8-10-301 in Tables VII-AE, AG, CK, and CL.

BAAQMD Regulation 9, Rule 1"Sulfur Dioxide":
In Table IV-DV, 9-1-313.2 has been corrected to show that it is federally enforceable.

V. Schedule of Compliance
No change has been made to this section.

VI. Permit Conditions
As part of the Title V permit reopening, the District is proposing changes made to several permit conditions. These include: conditions regarding flares and Regulation 9-10 requirements, and, as appropriate, revised conditions for clarity and enforceability. The Title V permit is being updated to accurately reflect these applicable requirements. All changes to existing permit conditions are clearly shown in "strike-out/underline" format in the proposed permit. When the permit is issued, all 'strikeout" language will be deleted; all "underline" language will be retained, subject to consideration of comments received.

Revisions were made to the permit conditions for existing sources as follows:

Condition # 4288
Part 7 was added to require a continuous temperature monitor to verify compliance with the temperature requirement in Part 6 of the condition. This error in omission was corrected per the EPA's comment to Revision 1.

Condition # 12271
Compliance with 9-1-313.2 will be demonstrated by the facility by the monitoring of H2S at the two fuel gas distribution headers and by monitoring the NH3 concentration in the Sour Water Stripper Bottoms Effluent. Compliance with much more stringent H2S and NH3 limits supersedes compliance with 9-1-313.2. As a result, Part 115 has been amended to delete the sampling and source testing with requirements that reflect that compliance will be demonstrated using existing monitoring (H2S monitoring on fuel gas, NH3 monitoring on sour water stripper bottoms).

Condition # 18618
The throughput limits of S1430 and S1764 in Part 1 were corrected to reflect that it reflected the amount of material produced. The throughput limit for S1507 in Part 1 was amended to correct the typographical error; the limit should be 5,568 MMBTU/day and not 55,568 MMBTU/day.

Compliance with 9-1-313.2 will be demonstrated by the facility by the monitoring of H2S at the two fuel gas distribution headers and by monitoring the NH3 concentration in the Sour Water Stripper Bottoms Effluent. Compliance with much more stringent H2S and NH3 limits supersedes compliance with 9-1-313.2. As a result, Part 10 has been amended to delete the sampling and source testing with requirements that reflect that compliance will be demonstrated using existing monitoring (H2S monitoring on fuel gas, NH3 monitoring on sour water stripper bottoms).

The throughput of S4190 through S4193 were corrected to fix an administrative error. The initial throughput limits were based on inaccurate numbers that did not reflect actual design capacity of the combustion units. These initial numbers have been replaced with actual design capacity numbers. Also, these combustion units have had no physical modifications that have increased capacity since initial startup in 1996, and no emission limit exceedances have occurred since the initial startup of these units. Again, this change is considered a correction to an administrative error.

Part 11 was amended to accommodate the refinery's business concern for this state only requirement for notification. Definitions of process unit, start-up and shutdown were also added to the glossary.

Parts 12 and 13 were deleted and replaced with new flare monitoring language. The following discussion is provided for flares to explain the new flare monitoring conditions and to address comments previously received regarding them. Shell commented that S1472 should be combined with S1471 limit, because S1472 is essentially a backup flare for S1471. The facility also requested a correction of a typo in Part 13 and a clarification in Parts 14 and 15 that specifies that Parts 14 and 15 only apply to those sources listed in Part 12 and correct the reference number. The facility also requested correction of reference number in Parts 16 and 17 created when these new parts were added into the existing document. In Part 18, the same future effective date was added to be consistent with the other flare parts listed of this condition.

Parts 12 through 19 were returned to their prior wording because they were mistakenly set to "sunset" on June 1, 2004.

Flares

All of the refinery Title V permits contain permit conditions implementing requirements for flares. As explained in the response to comments on the initial Title V permit issuance, development of Title V permit conditions related to flaring occurred in parallel with the District's rulemaking on flare monitoring. The flare monitoring rule (BAAQMD 12-11) addressed many of the issues that the District was attempting to address in parallel through Title V, and so the Title V effort was to a significant extent subsumed by incorporation of 12-11 into the final permits. The District's flare monitoring rule in some ways went beyond similar existing regulations promulgated by other agencies and in that sense was unprecedented in scope and effect. As far as the District is aware, its efforts to craft Title V permit conditions is similarly innovative, and similarly has undergone re-evaluation and evolution. Even prior to issuance of the refinery Title V permits, District staff had begun a re-evaluation of some of the approaches and determinations slated for inclusion in the final permits. The current proposal to revise certain Title V permit conditions for flares is the outcome of that re-evaluation. The future effective dates attached to some of the Title V flare conditions was, in part, a reflection of the expectation that a re-evaluation was underway and that some additional time should be allowed before effort and expense were invested in a particular approach.

All of the flare conditions that were added during the initial Title V permit issuance process proposed for deletion and replacement with new conditions. The new conditions address proper operation, monitoring for visible emissions, and enforcement of determinations that NSPS Subpart J sulfur monitoring is not applicable.

The new conditions apply only to flares that are subject to Regulation 12-11. All of the flares that are fully exempt from 12-11 (vapor recovery flares, wastewater flares) operate under conditions, and burn materials, that are unlikely to result in visible emissions. Additionally, because they are not emergency flares, they are not likely to encounter flow rates above capacity. The reasons that led to exemption of these flares from 12-11 are also the reasons why additional Title V conditions addressing these three areas are not appropriate. .

Proper operation

Proper flare operation is being addressed to support the conclusion that flare emissions are not subject to the miscellaneous VOC regulation, BAAQMD 8-2. A source is exempt from District Regulation 8 (and therefore from 8-2) if, pursuant to 8-1-110.3, organic compounds are reduced by at least 90% due to abatement by incineration. Flare emissions qualify for this exemption if there is a reasonable assurance that 90% reduction is occurring. The District surveyed available information on flare efficiency and concluded there is a strong assurance that a 90% reduction is achieved during proper flare operation. The Title V permit conditions being proposed are intended to provide assurance that flares will be operated properly.

The District's Advisory Council has reviewed flare available information about refinery flares, and has rendered an opinion that hydrocarbon destruction efficiency of a properly designed and operated flare is greater than 98%. District staff have been working with the facilities, activists, citizen groups, and various experts to develop flare monitoring and control regulations. In the course of that work, the current body of knowledge about refinery flare operation has been reviewed. A consensus seems to be that the modern steam-assisted flares commonly found at refineries are "properly designed" relative to the purposes for which they are used. District staff have determined that a properly designed flare may be said to be "properly operated" if the flow rate is below the design capacity, if the gas being flared has sufficient fuel value (i.e., 300 BTU/cubic foot), and if flame is present at all times.

The District is in the process of gathering additional information about refinery flare design with the goal of further informing its conclusions regarding the proper design and operation of flares at the bay area refineries. The information being collected includes information relevant to the flare design elements contained in 40 CFR 60.18. At the time of issuance of this permit revision, that information gathering effort has not been completed. The flare design information and any conclusions drawn from it by the District will be included in the statement of basis for the next revision of the refinery permits, currently scheduled for Spring of 2005.

Design Capacity

Part 12 of the flare condition requires the facility to operate the flare below its rated capacity. This raises the question: what happens if more gas needs to be flared than the flare is rated for? In that situation, all of the gas will be routed to the flare; the alternative is to vent the gas to the atmosphere without abatement, which in turn would precipitate the extreme safety hazard that flares are designed to prevent. The District therefore anticipates that the safe operation of the flare will cause the flare to exceed its capacity, with a possible reduction in destruction efficiency. This will result in a violation, but the event will be handled safely. The proposed permit condition is not expected to prohibit the use of the flare as necessary to avoid safety hazards. There is a functional overlap between the goal of preventing release of uncombusted gases for safety reasons, and the 90% reduction threshold contained in 8-1-110.3. A failure to achieve at least 90% reduction would be at odds with preventing the safety hazard posed from release of uncombusted gases. In this sense, flares are categorically distinguishable from the typical “end of pipe” air pollution control device that is installed to meet a regulatory requirement but does not otherwise promote the self-interest of the facility. Refineries have a strong interest in proper flare operation that prevents the potentially severe consequence of releasing explosive gases over or near the facility. The fact that proper operation for safety purposes is also proper operation for District regulatory purposes provides a substantial assurance that 90% will be achieved. The permit condition prohibiting operation above rated capacity provides an additional regulatory enforcement tool to deter such events from occurring.

Part 13 requires recordkeeping to demonstrate compliance with Part 12.

Fuel value

Flares that are designed to receive low-btu gas are equipped with supplemental fuel gas lines to ensure that the gas vented to the flares has sufficient heating value. The new flare monitoring rule, 12-11, requires vent gas composition monitoring. District staff have presumed that the systems designed to ensure that flared gases are combustible are working properly. The monitoring required by 12-11 will provide a means of verifying this.

Flame

12-11-503 requires monitoring to ensure that flame is present. A permit condition would be redundant.

Visible emissions

The flare monitoring rule is designed to gather information to ensure that flares are properly operated, and to be used for possible a future control measure. It is not designed to assure compliance with other applicable rules, specifically those regarding particulate and visible emissions. Therefore, the District is proposing conditions to provide a reasonable assurance of compliance with visible emissions and particulate emissions standards.

The new Title V permit condition requires frequent monitoring of a flare during a flaring event. The operator must check the flare for visible emissions every half hour until the flaring event is over, or until a violation is detected.

If the flare is under video surveillance, and if the video image is of sufficient clarity for the operator to say with certainty that no visible emissions are present, the video may be used. Otherwise, the operator must directly view the flare. Regulation 6-301 is the Ringelmann standard, and requires a trained observer to read the smoke plume. When a trained observer is not available, the facilities have agreed to operate under a more stringent “no visible emissions” standard.

Part 15 states that, if the surveillance is by a trained observer, compliance will be demonstrated using EPA Method 9 (the method specified in Regulation 6-301). Otherwise, an untrained observer observes the stack, and if visible emissions are detected for three consecutive minutes, the flare violates the surrogate standard contained in the permit condition.

NSPS Subpart J

Any flare built or modified after June 11, 1973 is subject to NSPS Subpart J. Modification of a flare, as defined in Subpart J, would likely only occur if the burner tip is replaced by one with a larger capacity – which is likely to be a rare event. As a result, NSPS Subpart J typically applies to flares that are built after the effective date. The following table lists each flare and indicates whether it is subject to Subpart J:

Source Number	Sources Controlled	Construction Date	Applicable to Subpart J (Y/N)	Reason why flare is properly designed
A100 Marine Vapor Recovery Thermal Oxidizer	S2001, S2002, S2003, S2004	1991	Y	This system was designed by the McGill Environmental Services company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell’s Engineering

Source Number	Sources Controlled	Construction Date	Applicable to Subpart J (Y/N)	Reason why flare is properly designed
				Guidelines and General Specifications(EGGS) which assure that it was properly designed.
A101 Vapor Recovery System Flare #2	S610, S611, S612, S613, S1133, S1134, S1751, S1752, S1753, S1754, S1757, S1758, S4334	1992	N	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed
A102 Vapor Recovery System Flare #3	S483, S484, S530, S532	1992	N	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications.(EGGS) which assure that it was properly designed.
A103 Vapor Recovery System Flare #1	S13, S14, S534, S1139	1992	N	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
S1470 Propane Loading Rack Flare	S1526, S4338	1966	N	This system was designed by the John Zinc company. It was designed and

Source Number	Sources Controlled	Construction Date	Applicable to Subpart J (Y/N)	Reason why flare is properly designed
				constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
S1471 LOP Auxiliary Flare; S1472 LOP Main Flare	S1114, S1115, S1416, S1417, S1420, S1421, S1423, S1424, S1425, S1426, S1427, S1428, S1429, S1430, S1431, S1432, S1433, S1434, S1435, S1436, S1445, S1446, S1447, S1448, S1449, S2012, S4170	1966	N	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
A 1501 F-56 Backup Thermal Oxidizer for Sulfur Plants 1 and 2	S1431, S1432	1966	Y	This system was designed by both the John Zinc company and Saracco Tank & Manufacturing Corporation. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
A1517 F-77 Primary Thermal Oxidizer for Sulfur Plants 1 and 2	S1431, S1432	1974	Y	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and

Source Number	Sources Controlled	Construction Date	Applicable to Subpart J (Y/N)	Reason why flare is properly designed
				General Specifications(EGGS) which assure that it was properly designed.
A 1518 F-109 Catalytic Oxidizer for SCOT No. 3	S1765	1983	Y	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
S1771 Flexigas Flare	S1759	1983	Y	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
S1772 OPCEN HC Flare	S1759, S1764, S1770, S1774	1982	N	This system was designed by the John Zinc company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
A4181 SCOT No. 4	S4180	1996	Y	This system was designed by the Pritchard Corporation. It was designed and

Source Number	Sources Controlled	Construction Date	Applicable to Subpart J (Y/N)	Reason why flare is properly designed
				constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.
S4201 Clean Fuels Flare (LRGO Flare)	S4001, S4020, S4050, S4080, S4140, S4160, S4180, S4211, S4212	1995	N	This system was designed by the Callidus Company. It was designed and constructed per applicable industry & regulatory requirements as well as Shell's Engineering Guidelines and General Specifications(EGGS) which assure that it was properly designed.

There is only one requirement for flares subject to subpart J: a limitation on the sulfur content of gas combusted, and the monitoring to demonstrate compliance. Subpart J exempts from this requirement the flaring of upset gases, and fuel gas that is the result of an emergency breakdown. However, Subpart A applies because the exemption is only from this section and not from Subpart J entirely.

Some of the facilities have identified NSPS flares (flares built after 1973) that are not designed to burn anything other than upset gases or fuel gases that result from emergency breakdowns. These flares are therefore exempt from the NSPS monitoring requirement, provided they are used only in that manner. However, at least some of these flares have a potential for broader use because the physical construction that enables flaring of gases from upsets or emergencies also enables flaring of gases from routine processes. **Part 19** imposes a condition on these flares to assure compliance with the exemption criteria. The same prohibition found in Part 19 could be enforced by directly enforcing applicability of Subpart J, that is, by a determination that the facility has been in violation of Subpart J if, for instance, routine disposal of gases through flaring has occurred. However, enforcement of Subpart J in federal court (through the CAA citizen enforcement provisions) is an unwieldy tool for use by a permitting agency such as the District that can much more readily enforce in state court. By incorporating the prohibition against routine flaring into Title V permits, enforcement of this prohibition becomes substantially more feasible for the District.

Part 19 imposes a condition on these flares to assure compliance with the exemption criteria.

Issues raised by comments

The District received a number of comments related to flares during the initial permit issuance. In anticipation that similar comments may be received regarding this proposal, the District here offers anticipatory responses. The formerly-received comments are presented below, together with a response that tells how the comment is addressed by the revised permit condition. The District will of course respond to any new comments received or to refinements of comments noted here.

Comment: The Air District should require the performance of independent testing using available methods for monitoring flare efficiency under worst case conditions.
Response: There is no way to directly monitor flare efficiency. However, it is possible to monitor flare parameters (flow rate, etc) in a way to ensure that flares operate as designed. This is the approach taken in Part 1 of this proposal. The District disagrees with the suggestion that, because performance measurement techniques are limited, it follows that specification of minimum flare destruction efficiency is contrary to Title V requirements. Flare destruction efficiency is a provision of 12-11, and therefore should be incorporated in the permit. Despite the technical limits of direct compliance verification, the requirement has relevance and import as a design requirement.

This comment, proposing as it does "independent testing" and "worst case conditions," is not a monitoring proposal, but a recommendation for data development. While perhaps appropriate for rule development, such a proposal is not within the scope of Title V.

Comment: A flaring event that lasts between 3 and 15 minutes could exceed opacity limits, and this type of violation would go unmonitored under existing permit monitoring requirements. The District implies that opacity limitations need only be monitored if the emission is "significant" or is " a real problem." The District's opacity regulation does not allow for these exemptions from its requirements.
Response: The comment is based upon the faulty premise that the purpose of Title V monitoring is to detect every violation. Continuous monitoring for violations can be cost-prohibitive, impractical, and even, in a case such as this, at odds with good air pollution practices. The purpose of Title V monitoring is to provide reasonable assurance of compliance. This requires a balance between cost and difficulty of the testing, and the likelihood and severity of non-compliance. See, for example, EPA's guidance on the required monitoring for other sources subject to visible emission standards.

Because the visual observation and sample collection that comprise flare monitoring are going to be performed by the process unit operator, both Rule 12-11 and the permit condition require the initial monitoring to occur 30 minutes into the episode. This is to allow the operator to place his or her attention, at the beginning of the event, where it belongs: trying to address the conditions that are resulting in flaring. A flaring event that can be ended within 15 minutes should be, and should not be prolonged while the operator goes out to look at the stack. A flaring event that goes on for thirty minutes, though, is probably not going to be resolved so quickly. Three minutes to check on the flare's appearance is not going to seriously affect the duration of the incident.

The frequency and duration of monitoring for visible emissions is a matter of judgment, balancing the value of information gained against the costs of collection. Taking into consideration all of the factors, District staff have determined that a periodic check every half hour provides the necessary assurance that significant non-compliance will be detected.

Comment: Regulation 8-2 should apply to refinery flares. Either monitoring to assure compliance with 8-2 should be imposed, or monitoring to assure compliance with the 85% destruction efficiency requirement in 8-1-110.3.
Response: Part 1 and Part 2 of the revised permit condition are intended to address this. By ensuring that the flare is properly operated, the condition assures that combustion efficiency is maintained at a high level, thereby assuring that application of the exemption contained in 8-1-110.3 is appropriate. As noted above, flare destruction efficiency cannot be measured directly, and so a reasonable substitute must be used. The District believes there is a reasonable basis for concluding that 90% destruction efficiency will be met because efficient destruction is the very reason for the existence of a flare. However, the permit conditions in this proposal will provide an added measure of assurance and a regulatory enforcement tool to supplement this inherent design goal.

Comment: The permit should contain monitoring to determine compliance with subpart J, including fuel H2S monitoring for those flares subject to the fuel H2S limit.
Response: The fuel H2S monitoring is, in fact, the only monitoring needed to determine compliance with subpart J. This has been included in Table IV an VII for each flare subject to the limit. Flares subject to Subpart J, but not the limit, because they only burn upset gas, are subject to Part 7 of the flare condition.

Comment: Please also include record-keeping and reporting requirements for those flares subject to NSPS J but exempt from the fuel H2S limit.
Response: It is unclear what monitoring is being requested. If the proposal is to include monitoring to ensure that non-exempt gases are not vented to exempt flares, the requirements of Regulation 12-11-401 should suffice. We do not consider, however, this monitoring to be federally enforceable. The only federally enforceable monitoring for assuring compliance with Subpart J is spelled out in Subpart J.

EPA Comment: We also understand that the District will include opacity monitoring on process flares for compliance with Ringlemann/opacity Regulations 6-301 & 302 and each of the requirements that apply on a unit specific basis, and mark all flame monitoring as "continuous" monitoring.
Response: The new condition includes visible emission monitoring to assure compliance with Regulations 6-301 and 6-302.

EPA Comment: Where the necessary Title V monitoring coincides with the District's Regulation 12-11 flare monitoring rule, the District may list Regulation 12-11 as the monitoring that will satisfy Title V if it is listed as federally enforceable.
Response: Only monitoring to assure compliance with a federally enforceable limit is supposed to be labeled as "federally enforceable."

EPA comment: For sources that must meet a given control efficiency, the District must include a compliance determination and monitoring method for those requirements.
Response: The District has determined that properly designed, properly operated flare meet 98% destruction efficiency. All refinery flares are properly designed and some assurance of proper operation derives from the fact that an improperly operated flare is not an effective safety device. Monitoring to provide an additional assurance that each flare is properly operated has been added to the permit. See discussion above.

EPA Comment 7: For thermal oxidizers, the permit evaluations [*sic*] must also contain the applicable requirements.
Response: The District permit contains all requirements identified by the District as applicable.

EPA Comment 8: The permits must also require monitoring the flow rate if necessary to determine compliance with residence time requirements. This monitoring is in addition to the temperature monitoring that the District already includes.
Response: The Shell refinery has no thermal oxidizers subject to residence time requirements.

EPA also submitted comments on the proposed Shell Martinez Refinery Permit after the deadline (EPA letter from Gerardo Rios to Steve Hill, dated 10/31/03). The comments related to flares are presented below.

1. Condition 18618, #12 (p. 411) implies that “intentional” releases to flares are allowed, in which case NSPS sub-part J applies to all units built after the date listed in the standard and a non-applicability permit shield for these flares cannot be included.
Response: Condition 18618 part 12 does not imply that intentional releases are allowed at all flares; it is silent on the issue. The applicability of Subpart J to each flare, as determined by the District, is reflected in Table IV.

2. When reevaluating and documenting the determinations for NSPS J, please also look at the applicability of NSPS J to thermal oxidizers.
Response: Subpart J applies to all combustion devices at the facility constructed after June 11, 1973.

3. Table VII-AO (p.460) lists P/E record provision pursuant to NSPS J for S1471 and S1472 though there is no emergency only provision in the permit nor any citation to NSPS J for these units. Please explain if these units are subject to NSPS J; if they are subject please specify if they are subject to the fuel limit or exempt based on emergency/process upset use only and add continuous H_2S monitoring. If these units are exempt please retain the record keeping provision and provide an explanation in the statement of basis.
Response: These units are subject to NSPS J. However, NSPS J exempts flares to the extent that they are used only for burning upset gases or gases from emergency malfunctions. The refinery has stated that these flares are used only for this purpose, and the District is not aware of information to the contrary. The relevant recordkeeping requirement is included in Part 2 of the new flare condition.

4. In addressing the applicability of 40 CFR 60, Subpart A, please explain why these requirements, particularly 60.11, have been deleted from Table IV-AXa for S-4201 and

abatement devices 101, 102, and 103 (p164-165). Please ensure that all flares and thermal oxidizers subject to 60.11 have this requirement listed in the permit. We would recommend making 60.11 a refinery-wide requirement as was done for the other four Bay Area permits recently submitted for review.
Response: These flares are not subject to Subpart J because they meet the exemption in 60.104(a)(1). They are only used for process upset/malfunction. Additionally, they are not control devices for any sources subject to NSPS or NESHAPS. Therefore the flares are not subject to any parts of Part 60 Subpart A or Part 63 Subpart A.

5. Similarly, when the District addresses applicability of 40 CFR 63, Subpart CC, please note that any flare subject to 63.643 must either comply with 63.11(b), or else meet the requirements of 63.643(a)(2), in which case refineries must be capable of measuring the control efficiency of the flare. Please ensure that each flare subject to 63.11 has this requirement listed in the permit. The District may want to consider making 63.11 a refinery-wide condition as was done in the permits for Chevron, Conoco, and Valero.
Response: There are no flares that are used to meet 63.643 requirement for process vents. The process vents go to vapor recovery and fuel gas.

6. Table IIB (p. 34) says that there are no applicable requirements for flares S-1771 and 1772. However, table IV-BW (p. 213) lists several requirements for these sources. Please correct this discrepancy.
Response: There is no discrepancy. Table IIB lists numerical requirements that apply to abatement devices that require outlet monitoring. There are no such requirements for S1771 or S1772.

7. Table IV-BXa lists condition 7618 as an applicable requirement for 1771. However, on page 322 (Section VI, permit conditions, 7618) 1771 is not one of the subject sources. Instead, source 1772 is listed as subject, while table IV-BW (p. 213) does not list 1772 as subject. Please correct this discrepancy.
Response: The error was in the list of sources at the beginning of Condition 7618 in Section VI. The permit has now been corrected. S1771 is subject to Condition 7618, S1772 is not

8. We suggest listing Rule 12-11 as a requirement for all flares. It is currently just listed for S-4201, and A-101, 102, and 103.
Response: Not all flares are subject to Rule 12-11. Vapor recovery flares, for example, are exempt.

Changes made to permit in November 2004:

Corrections made to permit condition 18618:

Part 15:

Sections a, b, a, and b have been renumbered to a, b, c, and d. The reference to "part 5" in the renumbered section "d" has been changed to reference part 17.

Part 18:

The "and" in the sentence which reads "….. shall conduct a visual emission inspection weekly following the protocol in Part 16 a, b *and* c…." has been replaced with an "or". The sentence now reads "….. shall conduct a visual emission inspection weekly following the protocol in Part 16 a, b *or* c….".

Part 19:

Sources S1471, S1472, and S1772 have been deleted from part 19 of permit condition 18618. Sources S1471 and S1472 are currently not subject to Subpart J. A resolution has not been reached between Shell and the EPA as to Subpart J's applicability to the above referenced flares. Part 19 of permit condition addresses flares that exclusively burn process upset gases as defined in 60.101(e)(1) or fuel gas as defined in 60.101(d) that is released to the flare as a result of relief valve leakage or other emergency malfunctions. Source S1772 is subject to Subpart J and meets the H2S limit of 163 ppm in the fuel gas outlined in 60.104(a)(1). Source S1772 complies with the monitoring requirements in 60.105(a)(4), since the flare is equipped with an analyzer to continuously monitor and record the concentration of H2S in the fuel gas before being burned in it. Since the flare does not exclusively burn process upset gases as defined in 60.101(e)(1), nor fuel gases as defined in 60.101(d) that is released to the flare as a result of relief valve leakage or other emergency malfunctions, it can burn non-process gases in it as long as the concentration of H2S in the gases burned is continuously monitored and recorded. In light of the above the reference to S1772 has been deleted from part 19 of permit condition 18618. In similar fashion, the reference to part 19 of permit condition 18618 has been deleted from Table IV-AXc in the permit.

Condition # 18265

NOx Box

The following discussion explains changes to refinery permit conditions prescribing monitoring for compliance with Regulation 9-10 at units for which CEMs are not required, commonly known as the "NOx Box" permit conditions. To facilitate the reader's understanding of the proposed changes, this discussion provides background on the 9-10 rule and CEM-equivalency monitoring provided for therein.

Regulation 9-10 requires each refinery to reduce NOx emissions from boilers and heaters. All of the boilers and heaters at each refinery above 10 MMBTU that were in existence on January 5, 1994 are included in determination of compliance with a facility-wide average emission rate of 0.033 lb/MMBtu. BAAQMD 9-10-301.

In order to demonstrate compliance, each affected heater must be equipped with a NOx CEM, or equivalent verification system (BAAQMD 9-10-502). Where combustion processes are sufficiently static over time, emissions factors combined with MMBtu data can be used to verify compliance with accuracy equivalent to that of CEMs. An emissions factor approach can be deemed equivalent if the integrity of the emissions factors can be assured. The NOx Box approach does this by: 1) verifying emissions factor accuracy through source-testing, 2) defining the parameters of operation within which emissions factors have been proven, and 3) requiring that any excursions outside of those parameters be the subject of a new source test.

Source tests to establish the NOx Box are conducted at extreme operating conditions (the “corners” of the NOx Box). As long as the facility operates within the perimeter defined by these source tests, emissions are assumed to be equal to the highest emission rate tested. By monitoring firing rate and O2 in the exhaust, the validity of using the emission factor is reasonably assured. Periodic source tests confirm that the emission factor is still valid for the operating range. Operation outside the box results in scrutiny to determine compliance with the emission standard, including conduct of a test at the unproven conditions.

That the NOx Box approach is consistent with the intent of Regulation 9-10 was evidenced in the District Staff Report for that rule, which stated:

> “District staff recommends that CEMS be only required on units equipped with SCR and SNCR due to high capital and maintenance costs. NOx can vary significantly for SCR and SNCR units based on temperature and amount of ammonia injected. On the contrary, NOx from non-SCR and SNCR units equipped with FGR and low NOx burners and are relatively stable and CEMS should not be necessary for these units.”

Rule Development Staff Report, Regulation 9, Rule 10, November 19, 1993, p. 7.

After the public comment period for Revision 1, comments were received from the Western States Petroleum Association (WSPA). As a result of those comments, the conditions to the NOx box were modified slightly to fix typographical and grammatical errors and to allow an extension of source test report submittals if requested by the refineries. Source testing is also required within 30 days of startup if the source has been shutdown for a period of time that is longer than the required source test frequency.

Federal Enforceability

9-10-301 and 9-10-502 are not included in the SIP, and are therefore not federally enforceable. Revisions to the NOx Box Condition in the Title V permit may be made by Administrative Amendment.. BAAQMD 2-6-201.

Changes from the current conditions

The current Title V refinery permits contain NOx Box conditions based on an earlier District policy for demonstrating verification system equivalence. Experience with implementation of these conditions has allowed the District to identify certain areas for improvement. One problem with the current conditions is that it allows sustained operation at conditions that have never been tested for compliance with the NOx Box emission factor.

The proposed condition addresses this problem, and several others that have been raised by EPA, the facilities, and the public.

The changes can be summarized as follows:

- The old policy allowed for operation at conditions outside the perimeter of test conditions. The reason for this was to account for the fact that requiring the facility to test the furnace at specific conditions could have an expensive impact on production. While this is still true, there was also considerable opportunity for circumvention, where a facility could have sustained operation outside the box, and then test at conditions that happened to be well within the box. The new policy requires that a test be conducted that would capture the new conditions. The impact on process operation is mitigated by allowing the facility to delay testing until the next periodic source test.
- The old policy used one emission factor for all allowable operating conditions. The new policy allows two boxes, with two factors. One lower factor applies to routine operating conditions, while another higher factor may be used for normal operation at higher levels. This provides more flexibility without sacrificing the assurance of compliance.
- The NOx box can be a 5-sided polygon, rather than a simple box.
- Because the policy is, in some ways, more stringent, time to conduct the source tests to establish the new boxes has been allowed. Existing NOx Box conditions will remain in effect until June 1, 2004, when they will be replaced by the new conditions.
- Under the old policy, two Notices of Violations (NOVs) issued because of a single source would automatically trigger a requirement to install a NOx CEM. Under the new policy, two NOVs will trigger a review by District staff to determine if the NOx Box for that source is still deemed equivalent to a NOx CEM. If it is not, a NOx CEM will be required.
- The new policy allows a facility to operate at low firing rates (idling) for a limited period of time, without having to expand the box to include those conditions. There are two reasons for this. First, emissions at low fire are much lower than normal, even if the emission factor is higher. Second, it is an extreme hardship to require the facility to turn down its production in order to test at very low fire conditions.

The following summarizes the various parts of the proposed NOx Box conditions:

Part 1 of the condition lists all of the combustion devices subject to 9-10-301.

Part 2 requires installation of oxygen monitors. This is necessary because some of the smaller heaters are not required by Regulation 9-10 to have oxygen monitors. Oxygen content must be monitored continuously to demonstrate compliance with the condition. Operators will be allowed six months to install any newly-required oxygen monitors.

Part 3 requires operation of each combustion device within the box. Failure to operate within the box is a violation of this condition, unless excused by one of the deviation procedures in Part 7.

Part 3B covers small units (<25MMBH). The NOx Box for small units is essentially the entire potential operating range for the unit. Rather than establishing the "corners" of the box, the box is defined to be the full range of firing rates, and all possible oxygen contents. Existing data may be used to establish the emission factor that will be applied. Unless the unit is fired above its rated capacity, it is not possible to operate outside the box. An annual source test will confirm that the factor used is still valid.

Part 4 requires the operators to conduct the source tests necessary to establish the initial NOx boxes. Each combustion device may have two NOx boxes, one larger than the other. The smaller NOx box, with the lower emission factor, represents the typical operating range of the unit. As long as the unit operates within this range, the listed emission factor and the measured firing rate will be used to determine the unit's contribution to the refinery-wide average. The operator may choose to have a second, larger box, to cover unusual operating conditions. This larger box will have a higher emission factor associated with it. The allowance for two boxes means that a higher emission factor can be used for occasional operation at harsher, higher-emitting conditions, while still allowing use of a lower emission factor during normal operation. The District believes this is an appropriate degree of flexibility that does not unduly complicate implementation.

The NOx box may be expanded by replacing corner points with new ones that have been tested. The operator may also decide to increase the emission factor associated with a NOx box. This may allow operation at a wider range of conditions; it may be necessary because a source test has shown that the old factor is no longer valid; it may be desirable to provide a margin of compliance.

Part 5 describes the actual NOx box.

Part 5A contains the table that defines the perimeter of the NOx box, the perimeter of the second NOx box (if the operator chooses to use one), and the emission factors used

Part 5B allows established emission factors to be used for operation outside the box at low firing rate conditions. Although NOx or CO emission factors (expressed as lb/MMBtu) may be higher under these conditions, overall emissions are lower because of the greatly reduced firing rate. Testing under these conditions would have a significant cost because the operator would need to reduce firing (and production) to conduct a test. Instead, reduced firing will be treated in the same manner as a shutdown: for purposes of calculating the refinery average, the furnace will be treated as if it were operating at its normal firing rate and emission rate. In other words, though emission factors may be inaccurate in this low-firing range, there is not a possibility that emissions will be underestimated.

Part 5C allows a facility to conduct source tests outside the NOx box in order to increase the range of allowable operation.

Part 6 describes the steps to be taken if operation outside the box occurs.

Operation outside the range for which the emission factor has been demonstrated raises several questions. Is the emission factor valid for these conditions? If not, and if emissions were higher, did the higher emissions result in a violation of the refinery-wide average? The procedures of this part answer these questions.

Operation outside the NOx box triggers a requirement for the operator to test the unit under conditions that capture the new operating conditions. The test may be conducted in lieu of the next scheduled periodic source test (small furnaces, which may not normally be tested so soon, will have to be tested within 8 months). It is possible that the operator may not be able to reproduce the operating conditions during a source test. Failure to conduct the test will result in a violation of the Part 5 of the permit condition, and would be considered a violation of 9-10-502. If more than one such violation occurs during a 5-year period at a given unit, the District will review the NOx Box for that unit to determine whether it is, in fact, equivalent to a CEM. The District considered whether to establish in permit conditions a threshold for concluding that the NOx Box approach was inadequate for a particular unit and that CEMs must be installed. However, a simple algorithm for making this determination was not apparent. Instead, the District will evaluate each situation case by case, and will use its authorities to require installation of a CEM where appropriate.

If the test shows that emissions are below the factor used for the box, then no violation has occurred. The operator may choose to expand the box to utilize the new test results. This emission factor will then be used in the future.

If, however, the test shows that the emission factor for the new operating conditions exceeds the NOx box factor, the operator must reassess past emissions utilizing the higher emission factor. This may result in violations of the refinery-wide average (Regulation 9-10-301).

Part 7 requires periodic source tests to demonstrate that the NOx Box factor is still valid. Usually, tests will be conducted at whatever conditions the unit is operating at on the day of the test. If, however, it has been some time since the extreme corners of the box have been tested, or if there is reason to believe that difficult operating conditions are being avoided during tests, the APCO may require that the test be conducted under specific conditions.

Small furnaces are tested once per year. Large furnaces are tested every six months.

Part 8 requires periodic CO source tests for units equipped with NOx CEMs.

Part 9 requires installation of a CO CEM if two sources tests show CO levels greater than 200 ppm. Normal CO concentrations are an order of magnitude lower. One high CO reading is an anomaly. Two high readings are an indication that CO may be a problem, and continuous monitoring of firing rate and O2 is not equivalent to continuous monitoring for CO.

Part 10 requires maintenance of records for the monitoring required by the permit condition.

Condition # 20762
Part 1 of Condition # 20762 was amended to allow the use of other approved District methods in determining the vapor pressure of the organic liquids in the storage tank. Lab Method 28 is not accurate for low vapor pressure materials. Other, more reliable, methods exist.

VII. Applicable Limits and Compliance Monitoring Requirements

This section of the permit is a summary of numerical limits and related monitoring requirements for each source. The summary includes a citation for each monitoring requirement, frequency of monitoring, and type of monitoring. The applicable requirements for monitoring are completely contained in Sections IV, Source-Specific Applicable Requirements, and VI, Permit Conditions, of the permit.

Changes made to this section of the permit generally reflect the changes to other parts of the permit that have previously been discussed.

- Due to the changes noted in Table IV for S1772, in Section VII, Table VII-BH has been deleted. The requirements for SO2 and Condition 18618 were added into Table VII-BI for S1771. In addition, any applicable Condition 18618 requirements were added into Table VII-BJ for S1772.

The facility commented that alternative method under 60.13(l) for S1470 in Table VII-AN should be changed from continuous to periodic event to reflect actual monitoring frequency. The District agrees.

The two Tables VII-AO were relabeled to distinguish them as Table VII-AOa and Table VII-AOb.

Regulation 12-11 requirements were removed from A101 through A103 because these flares are used for vapor recovery flares.

The monitoring citation was corrected from Condition 18618 Part 12 to 18 in Table VII-BI.

The throughput limit of Condition 18618 Part 12 was corrected in Tables VII-BI, BJ, and CI. The limits were off by a factor of 1000.

S1772 was added to Part 19 of Condition 18618. Also this condition is added to Table IV-BX.

The NOx limits for Regulation 9-10-301 and 9-10-303 in Section VII Tables AP, AQ, AR, AT, AU, AX, BB, BL, CB, and CE were consolidated into one line item.

Tables VII-AU, AX, CB, and CE were amended to include Regulation 9-10-301 because it is an applicable requirement that was left out of those tables.

NSPS Subpart J requires that H2S in fuel gas be limited to 163 ppm if the fuel gas is combusted in an affected fuel gas combustion device. To demonstrate compliance, CEMs are required to monitor the H2S concentration of fuel gas. The primary fuel gas streams at the refinery include refinery fuel gas (RFG) and flexigas (FXG). Each of these fuel gas streams has an H2S CEM as

required by NSPS Subpart J. The definition of fuel gas under NSPS Subpart J also includes other "fuel gas" streams, such as process vent gases, if they are routed to an affected fuel gas combustion device. For these vent gases, the refinery does not use CEMS and instead utilizes alternative monitoring that is allowed under 60.13(i). In accordance with 60.13(i), U.S. EPA, Region IX, has approved the alternative monitoring plans. In the Title V permit, the facility requested the the appropriate monitoring requirements be reflected in Tables VII-AU, VII-CDa, VII-AX, VII-BY, VII-AQ, VII-CB, and VII-CC.
Table IV-BO correctly lists the conditions for source S1598. However, Table VII-BD required a minor amendment to include the testing requirements for Rules 8-7-301.6, 302.5 and 301.13. As a result, Table VII-BD was corrected to reflect these testing requirements.

Monitoring for flow rate, fuel value, and flame monitoring were added for S4201 and 1470 in Tables VII-CI amd VII-AN, respectively, to reflect monitoring requirements of 40 CFR 60.18.

Monitoring requirements for tanks were added to Tables VII-H, I, J, R, T and W for external floating roof tanks and Tables VII-P and VII-AD for internal floating roof tanks.

Changes made to permit in November 2004:

Diesel engines S5140, S6051 through S6060 are not subject to the 300 ppm sulfur dioxide standard in Regulation 9-1-302 "General Emission Limitation". This is because the refinery is conditionally exempt from the area monitoring requirements for the 300 ppm sulfur dioxide limitation in Section 9-1-302 "General Emission Limitation" per subsections 9-1-110.1 and 110.2. Specifically, Table IV-DV "Facility" in the permit contains the monitoring, records and reporting requirements contained in Regulation 1, including Sections 1-510, 530, 540, 542, 543, and 544 and hence meets the requirements outlined in subsection 9-1-110.1. In light of the above, Regulation 9-1-302 has been deleted from Table VII-CTa.

VIII. Test Methods

This section of the permit lists test methods that are associated with standards in District or other rules. It is included only for reference. In most cases, the test methods in the rules are source test methods that can be used to determine compliance but are not required on an ongoing basis. They are not applicable requirements.

If a rule or permit condition requires ongoing testing, the requirement will also appear in Section VI of the permit.

Changes to the permit in this revision:
None.

IX. Permit Shields

Changes made to this section of the permit generally reflect the changes to other parts of the permit that have previously been discussed.

- Due to the changes noted in Table IV and VII for S1772, S1772 should also be added to Permit Shield IX A-12 to indicate that it is not subject to Subpart J.

Based on comments received by EPA, the following table has been developed to further explain the reasoning behind the permit shields requested by the facility:

Table IX - #	Reasoning
1	Sources S1431, S1432, S1765, and S4180 are involved with the burning of sulfur, hydrogen sulfide, acid sludge, and other compounds used in the manufacture of sulfur compounds. As a result, it is not subject to Regulation 9-1-304, per 9-1-304.1.
1a	S1765 and S4180 are not subject to 40 CFR 63 Subpart UUU 63.1568(b)(2) and 63.1571 because these sources have already completed the initial performance tested that these two sections require.
2	S1470, A101, A102, and A103 are not subject to Regulation 12 per Regulation 12-11-110 because they are used exclusively to abate organic liquid storage tanks and/or loading racks.
4	S3000 combusts only natural gas and as a result are exempt from 40 CFR 60 Subpart J 60.104(a)(1). For A1501 and A1517, please refer to the discussion under Subpart J (last paragraph) in page 9.
5	S1759 and S4001 are not subject to 1-520, 1-522, 9-1-310, because they are not fluid cokers, catalytic cracking units, and coke calcining kilns and hence are not subject to these sections, which apply only to those types of sources.
6	S2001, S2002, S2003, and S2004 are not subject to Regulation 8-46 because they do not perform marine tank vessel to marine tank vessel loading, which this rule covers.
7	S4191 and S4193 is not subject to Regulation 9-9 because they are steam generators and Regulation 9-9 applies only to gas turbines.
8	The secondary water treatment processes and stormwater sewer systems are exempt per Regulation 8-8-113 from Regulation 8-8-301, 302, 306, 308 because Regulation 8-8-113 exempts the secondary water treatment processes and stormwater sewer systems from theses requirements.
9	The process drains are not subject to Regulation 8-8, because no requirements exist for process drains in Regulation 8-8.
10	The facility is not subject to Regulation 9-1-302 per Regulation 9-1-110, because it meets the requirements of 9-1-110.1 and 9-1-110.2: **9-1-110 Conditional Exemption, Area Monitoring:** The 300 ppm limitation of Section 9-1-302 shall not apply to a person who meets the requirements of subsections 9-1-110.1 and 110.2, provided such person has complied with those requirements prior to January 1, 1980. 110.1 A person shall be subject to the monitoring, records and reporting requirements contained in Regulation 1, including Sections 1-510, 530, 540, 542, 543, and 544. 110.2 A person shall not emit sulfur dioxide in quantities, which result in ground level concentrations of sulfur dioxide in excess of the limits specified in Section 9-1-301. This subsection shall not apply to ground level concentrations occurring on the property from which such emission occurs, provided such property, from the emission point to the point where the excess occurs, is physically secured against public access by the person responsible for the emission. (Amended Ma

	The facility is not subject to Regulation 9-1-303, because it only applies to ships.
	The facility is not subject to Regulation 9-1-309, because it has no sulfuric acid plants.
	The facility is not subject to Regulation 11-7 or 40 CFR 61 Subpart J and V, because it does not operate any “benzene service”.
	The facility is not subject to Regulation 11-11 or 40 CFR 61 Subpart Y and BB, because it does not store or transfer benzene.
	The facility is not subject to 40 CFR 60 Subpart D, because it does not operate any steam generators that are subject to this subpart.
	The facility is not subject to 40 CFR 60 Subpart Da, because it does not operate any steam generating units that are subject to this subpart.
	This facility is not subject to 40 CFR 60 Subpart Dc, because it does not operate any steam generators that are subject to this subpart.
	This facility is not subject to 40 CFR 60 Subpart R and XX, because it does not operate or own bulk gasoline terminals.
	This facility is not subject to 40 CFR Subpart F, G, H, III, NNN, and RRR because it does not operate any SOCMI operations.
	This facility is not subject to 40 CFR Subpart Q because it does not use chromium based water treatment chemicals.
	This facility is not subject to 40 CFR Subpart SS because it is not subject to any subpart that references the use of this subpart for air emissions control.
	This facility is not subject to 40 CFR 63 Subpart EEE because it does not own or operate any hazardous waste incinerator, cement kiln, or aggregate kiln.
11	S4161 is exempt from 40 CFR 60 Subpart J 60.105 because this source uses alternative monitoring in accordance with 60.13(i) for process swing absorption gas.
12	S1471, S1472, S1771, S1772, S4201, A101, A102, and A103 are exempt from the requirements of 40 CFR 60 Subpart J 60.104(a)(1) because they are used only to process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction and is therefore exempt.
	S1471, S1472, S1772, S4201, A101, A102, and A103 are exempt from the requirements of 40 CFR 60 Subpart J 60.105, because these flares are not subject to 40 CFR 60 Subpart J 60.104(a)(1), as explained above.
13a	S1771 is not subject to Regulation 12-11-401.2, 401.3, 401.5, 502.2, and 502.3 per Regulation 12-11-114, because it is used to exclusively burn flexicoker gas.
14	S1425 is not subject to 40 CFR 63 Subpart UUU 63.1566 per 40 CFR UUU 63.1562(f)(5), because the gaseous stream is routed to a fuel gas system .

Changes made to permit in response to EPA's October 8, 2004 letter:

In response to EPA comments (August 2, 2004 letter; Item 2), Table IX-A-10 has been modified to make clear the basis for the permit shields from BAAQMD Regulations 9-1-302, 9-1-303, and 11-7.

In response to EPA comments (August 2, 2004 letter; Item 2), permit shields from BAAQMD Regulation 9-1-309; BAAQMD Regulation 11, Rule 11; 40 CFR 60 - Subparts D, Da, Dc, XX, III, NNN, & RRR; 40 CFR 61 – Subparts J, V, Y, & BB; and 40 CFR 63 – Subparts F, G, H, Q, R, SS & EEE, have been deleted from Table IXA-10. This does not mean that the District has determined that any of these requirements apply to this facility, nor does it preclude the operator from requesting a permit shield at a later date. However, the operator has not supplied the information necessary to establish a permit shield.

In response to EPA comments (August 2, 2004 letter; Item 2), Table IXA-15 and Table IXA-16 have been added to contain permit shields from NSPS D, Da, Dc, and MACT EEE.

Table IX A - 10
Permit Shield for Non-applicable Requirements
FACILITY

Citation	Title or Description (Reason not applicable)
BAAQMD 9-1-302	Inorganic Gaseous Pollutants – Sulfur Dioxide, General Emission Limitation (The refinery is conditionally exempt from the area monitoring requirements for the 300 ppm sulfur dioxide limitation in Section 9-1-302 "General Emission Limitation" per subsections 9-1-110.1 and 110.2. Specifically, Table IV-DV "Facility" in the permit contains the monitoring, records and reporting requirements contained in Regulation 1, including Sections 1-510, 530, 540, 542, 543, and 544 and hence meets the requirements outlined in subsection 9-1-110.1.)
BAAQMD 9-1-303	Inorganic Gaseous Pollutants – Sulfur Dioxide, Emissions from Ships (The refinery is not subject to the 2000 ppm sulfur dioxide standard in Regulation 9-1-303 "Emissions from Ships", since all ships coming to the refinery come from outside the District. Therefore, the facility is not subject to 9-1-303)
BAAQMD Regulation 11, Rule 7	Hazardous Pollutants - Benzene ("In Benzene Service" is defined in Section 11-7-207 as any equipment, which either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The refinery does not have any stream that contains at least 10% benzene. Therefore, the facility is exempt from Regulation 11, Rule 7.)

Table IX A - 15
Permit Shield for Non-applicable Requirements
S1507 – UTIL CO Boiler 1, S1509 – UTIL CO Boiler 2,
S1512 – UTIL CO Boiler 3, S1514 – UTIL F-70 Boiler 4,
S4190 – UTIL Boiler 6 Gas Turbine 1,
S4191 – UTIL Boiler 6 Supplemental Steam Generator 1,
S4192 UTIL Boiler 6 Gas Turbine 2,
S4193 – UTIL Boiler 6 Supplemental Steam Generator 2

Citation	Title or Description (Reason not applicable)
40 CFR 60 Subpart D	Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced after August 17, 1971 (Sources S1507, S1509, S1512, and S1514 were constructed in 1966. Therefore, the above steam generators are not subject to NSPS D. 40 CFR 60.41(a) defines a fossil-fuel fired steam generating unit as “a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer. The gas turbines (S4190 and S4192) and duct burners (S4191 and S4193) located at the refinery’s cogeneration plant are neither furnaces nor boilers as defined under 40 CFR 60.41(a). Therefore, the gas turbines and duct burners are not subject to NSPS D.)
40 CFR 60 Subpart Da	Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 (Sources S1507, S1509, S1512, and S1514 do not generate electricity. Therefore, the above steam generators are not subject to NSPS Da. 40 CFR 60.41a defines an electric utility steam generating unit as “any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.” The gas turbines (S4190 and S4192) and duct burners (S4191 and S4193) located at the refinery’s cogeneration plant were not constructed with the intent of supplying more than one-third of their potential electric output capacity or for selling more than 25 MW of their electrical output to any utility power distribution system. Therefore, the gas turbines and duct burners are not subject to NSPS Da.)

Table IX A - 15
Permit Shield for Non-applicable Requirements
S1507 – UTIL CO Boiler 1, S1509 – UTIL CO Boiler 2,
S1512 – UTIL CO Boiler 3, S1514 – UTIL F-70 Boiler 4,
S4190 – UTIL Boiler 6 Gas Turbine 1,
S4191 – UTIL Boiler 6 Supplemental Steam Generator 1,
S4192 UTIL Boiler 6 Gas Turbine 2,
S4193 – UTIL Boiler 6 Supplemental Steam Generator 2

Citation	**Title or Description** **(Reason not applicable)**
40 CFR 60 Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (Sources S1507, S1509, S1512, and S1514 were constructed in 1966. Therefore, the above steam generators are not subject to NSPS Dc. 40 CFR 60.40c(a) regulates steam generating units that have a maximum design heat input capacity greater than 2.9 MW (10 million BTU/hr) and less than 29 MW (100 million BTU/hr). 40 CFR 60.41c defines a steam generating unit as "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." The maximum design heat input capacity of the cogenerating units – gas turbine & duct burner combination, sources (S4190 and S4191) and sources (S4192 and S4193) is 49MW per cogeneration unit. Therefore, the gas turbines and duct burners are not subject to NSPS Dc.)

Table IX A - 16
Permit Shield for Non-applicable Requirements
S1507 – UTIL CO Boiler 1,
S1509 – UTIL CO Boiler 2,
S1512 – UTIL CO Boiler 3

Citation	**Title or Description** **(Reason not applicable)**
40 CFR 63 Subpart EEE	National Emission Standards for Hazardous Air Pollutants for Hazardous Waste Incinerators (MACT EEE regulates three source categories: light weight aggregate kilns, cement kilns and hazardous waste incinerators. The CO boilers (S1507, S1509, and S1512) at the refinery do not meet the definition of either of the above three source categories. The definition for incinerator in MACT EEE (40 CFR 63.1201) refers to the definition in 40 CFR 260.10, which excludes boilers from the definition. The CO boilers at the refinery meet the definition of a boiler under 40 CFR 260.10.)

D. Alternate Operating Scenarios:

No alternate operating scenario has been requested for this facility.

E. Compliance Status:

<u>Changes to the permit in this revision:</u>

The facility is not currently in violation of any requirement. Moreover, the District has updated its review of recent violations and has not found a pattern of violations that would warrant imposition of a compliance schedule.

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APPENDIX A

GLOSSARY

ACT
Federal Clean Air Act

APCO
Air Pollution Control Officer: Head of Bay Area Air Quality Management District

ARB
Air Resources Board

BAAQMD
Bay Area Air Quality Management District

BACT
Best Available Control Technology

Basis
The underlying authority which allows the District to impose requirements.

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAPCOA
California Air Pollution Control Officers Association

CEQA
California Environmental Quality Act

CFR
The Code of Federal Regulations. 40 CFR contains the implementing regulations for federal environmental statutes such as the Clean Air Act. Parts 50-99 of 40 CFR contain the requirements for air pollution programs.

CO
Carbon Monoxide

CCR-2
Canadian Chemical Reclaimer heater.

Cumulative Increase
The sum of permitted emissions from each new or modified source since a specified date pursuant to BAAQMD Rule 2-1-403, Permit Conditions (as amended by the District Board on 7/17/91) and SIP Rule 2-1-403, Permit Conditions (as approved by EPA on 6/23/95). Used to determine whether threshold-based requirements are triggered.

District
The Bay Area Air Quality Management District

dscf

Dry Standard Cubic Feet

DNF
Dissolved Nitrogen Flotation.

EPA
The federal Environmental Protection Agency.

ETP
Effluent Treatment Plant.

Excluded
Not subject to any District regulations.

Federally Enforceable, FE
All limitations and conditions which are enforceable by the Administrator of the EPA including those requirements developed pursuant to 40 CFR Part 51, subpart I (NSR), Part 52.21 (PSD), Part 60 (NSPS), Part 61 (NESHAPs), Part 63 (MACT), and Part 72 (Permits Regulation, Acid Rain), including limitations and conditions contained in operating permits issued under an EPA-approved program that has been incorporated into the SIP.

FCC
Fluid Catalytic Cracker

FP
Filterable Particulate as measured by BAAQMD Method ST-15, Particulate.

Furfural Raff/Furfural Extr
These sources are heaters that contain furnaces within them. The heater is the overall unit and the combustion box is the furnace.

GDF
Gasoline Dispensing Facility

HAP
Hazardous Air Pollutant. Any pollutant listed pursuant to Section 112(b) of the Act. Also refers to the program mandated by Title I, Section 112, of the Act and implemented by 40 CFR Part 63.

H2SO4
Sulfuric Acid

ISOM
Isomerization plant.

Long ton
2200 pounds

Major Facility
A facility with potential emissions of: (1) at least 100 tons per year of regulated air pollutants, (2) at least 10 tons per year of any single hazardous air pollutant, and/or (3) at least 25 tons per year of any combination of hazardous air pollutants, or such lesser quantity of hazardous

air pollutants as determined by the EPA administrator.

MDEA
Methyl Diethanolamine

MFR
Major Facility Review. The District's term for the federal operating permit program mandated by Title V of the Federal Clean Air Act and implemented by District Regulation 2, Rule 6.

MOP
The District's Manual of Procedures.

MSDS
Material Safety Data Sheet

NAAQS
National Ambient Air Quality Standards

NESHAPS
National Emission Standards for Hazardous Air Pollutants. See in 40 CFR Parts 61 and 63.

NMHC
Non-methane Hydrocarbons (Same as NMOC)

NMOC
Non-methane Organic Compounds (Same as NMHC)

NOx
Oxides of nitrogen.

NSPS
Standards of Performance for New Stationary Sources. Federal standards for emissions from new stationary sources. Mandated by Title I, Section 111 of the Federal Clean Air Act, and implemented by 40 CFR Part 60 and District Regulation 10.

NSR
New Source Review. A federal program for pre-construction review and permitting of new and modified sources of pollutants for which criteria have been established in accordance with Section 108 of the Federal Clean Air Act. Mandated by Title I of the Federal Clean Air Act and implemented by 40 CFR Parts 51 and 52 and District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

Offset Requirement
A New Source Review requirement to provide federally enforceable emission offsets for the emissions from a new or modified source. Applies to emissions of POC, NOx, PM10, and SO2.

Phase II Acid Rain Facility
A facility that generates electricity for sale through fossil-fuel combustion and is not exempted by 40 CFR 72 from Titles IV and V of the Clean Air Act.

POC

Precursor Organic Compounds

PM
Particulate Matter

PM10
Particulate matter with aerodynamic equivalent diameter of less than or equal to 10 microns

PSD
Prevention of Significant Deterioration. A federal program for permitting new and modified sources of those air pollutants for which the District is classified "attainment" of the National Air Ambient Quality Standards. Mandated by Title I of the Act and implemented by both 40 CFR Part 52 and District Regulation 2, Rule 2.

SIP
State Implementation Plan. State and District programs and regulations approved by EPA and developed in order to attain the National Air Ambient Quality Standards. Mandated by Title I of the Act.

SO2
Sulfur dioxide

THC
Total Hydrocarbons (NMHC + Methane)

Title V
Title V of the federal Clean Air Act. Requires a federally enforceable operating permit program for major and certain other facilities.

TOC
Total Organic Compounds (NMOC + Methane, Same as THC)

TPH
Total Petroleum Hydrocarbons

TRMP
Toxic Risk Management Plan

TSP
Total Suspended Particulate

VOC
Volatile Organic Compounds

Units of Measure:

bbl	=	barrel
bhp	=	brake-horsepower
btu	=	British Thermal Unit
cfm	=	cubic feet per minute

g	=	grams
gal	=	gallon
gpm	=	gallons per minute
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inches
max	=	maximum
m^2	=	square meter
m	=	thousand
min	=	minute
mm	=	million
MMbtu	=	million btu
MMcf	=	million cubic feet
ppmv	=	parts per million, by volume
ppmw	=	parts per million, by weight
psia	=	pounds per square inch, absolute
psig	=	pounds per square inch, gauge
scfm	=	standard cubic feet per minute
yr	=	year

APPENDIX B

ALTERNATIVE MONITORING APPROVAL LETTER