Bay Area Air Quality Management District
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Final
Permit Evaluation
and
Statement of Basis
for
MAJOR FACILITY REVIEW PERMIT
Reopening – Revision 1

for

ConocoPhillips – San Francisco Refinery
Facility #A0016

Facility Address:
1380 San Pablo Avenue
Rodeo, CA 94572

Mailing Address:
1380 San Pablo Avenue
Rodeo, CA 94572

December, 2004

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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, to correct errors, and to incorporate some new sources and permit conditions contained in recently issued Authorities to Construct. All proposed changes are described in Appendix B. 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.

The changes to this document after EPA review are additional standard conditions in Section C.I. The changes to the permit after EPA review are discussed in Appendix B, Part 6, Items 21, 22, 23 and 24 and Appendix B, Part 11, Items 1 and 2 of this document.

B. Facility Description

This facility is a typical full-scale oil refinery, which processes crude oils and other feedstocks into refined petroleum products, primarily fuel products such as gasoline and fuel oils. Feedstocks are received via marine tanker vessels and pipeline, and petroleum products are shipped from the refinery the same way. Refining is a process which takes crude oil and distills it under atmospheric pressure into its primary components: gases (light ends), gasolines, kerosene and diesels (middle distillates), heavy distillates, and heavy bottoms. The heavy bottoms go on to a vacuum distillation unit to be distilled again, this time under a vacuum, to salvage any light ends or middle distillates that did not get separated under atmospheric pressure; the heaviest bottoms are eventually processed into coke. Other product components are processed by downstream units to be cleaned (hydrotreated), “cracked” into smaller molecules (catalytic or hydrocracking), reformed (catalytic reforming), or alkylated (alkylation) to form gasolines and high-octane blending components, or to have sulfur or other impurities removed to make diesel and other fuel oils. Refining byproducts include:

- wastewater, which is treated and discharged to the San Francisco Bay
- waste gases, which are collected and burned as fuel for refinery heaters, boilers and turbines
- sulfur, a salable by-product which is removed from feedstocks and intermediate products in the form of hydrogen sulfide and other sulfur-containing gases, and converted to a pure, solid form which is sold
- coke, a salable by-product that is the leftover solid material remaining after crude oil has been completely refined

Auxiliary facility operations include:

- a three-turbine power plant that burns refinery waste gases and natural gas, and which produces electrical power for the refinery and steam for various processing operations
- two hydrogen plants which produce pure hydrogen for use in various processing operations

Air emissions include both organic and inorganic gases that are emitted from storage tanks and from leakage from pipes and process vessels, as well as combustion emissions from refinery heaters and other combustion devices, and particulate emissions from operations such as coke and sulfur handling.

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)
- 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. 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.

ConocoPhillips also owns the ConocoPhillips Carbon Plant (Plant # A0022). Because the refinery and the carbon plant are so close together, have a common owner, and are in the same industrial grouping, they are considered to be one facility. Because District review of the original permit applications was close to completion at the time of this determination, the carbon plant has been issued a separate Title V permit, which is authorized by Title V regulations.

The District has determined that no refinery source is subject to additional applicable requirements due to the refinery's association with the carbon plant.

C. Permit Content

Additional information concerning the legal and factual basis of the Title V permit conditions is presented below. The information is organized by the relevant section of the Title V permit. All changes to the permit that have occurred after the permit was published for public comment are shown in strikeout/underline format. The changes are either corrections or responses to comments.

I. Standard Conditions

This section contains administrative requirements and conditions that apply to all facilities. If the Title IV (Acid Rain) requirements for certain fossil-fuel fired electrical generating facilities or the accidental release (40 CFR § 68) programs apply, the section will contain a standard condition pertaining to these programs. Many of these conditions derive from 40 CFR § 70.6, Permit Content, which dictates certain standard conditions that must be placed in the permit. The language that the District has developed for many of these requirements has been adopted into the BAAQMD Manual of Procedures, Volume II, Part 3, Section 4, and therefore must appear in the permit.

The standard conditions also contain references to BAAQMD Regulation 1 and Regulation 2. These are the District's General Provisions and Permitting rules. Condition I.J has been added to clarify that the capacity limits shown in Table II-A are enforceable limits.

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.

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

II. Equipment

This section of the permit lists all permitted or significant sources. Each source is identified by an S and a number (e.g., S24 or S-24).

Permitted sources are those sources that require a BAAQMD operating permit pursuant to BAAQMD Rule 2-1-302.

Significant sources are those sources that have a potential to emit of more than 2 tons of a "regulated air pollutant," as defined in BAAQMD Rule 2-6-222, per year or 400 pounds of a "hazardous air pollutant," as defined in BAAQMD Rule 2-6-210, per year.

All abatement (control) devices that control permitted or significant sources are listed. Each abatement device whose primary function is to reduce emissions is identified by an A and a number (e.g., A-24). If a source is also an abatement device, such as when an engine controls VOC emissions, it will be listed in this table but will have an "S" number. An abatement device that is also a source (such as a thermal oxidizer that burns fuel) will have an "A" number.

The equipment section is considered to be part of the facility description. It contains information that is necessary for applicability determinations, such as fuel types, contents or sizes of tanks, etc. This information is part of the factual basis of the permit.

Each of the permitted sources has previously been issued a permit to operate pursuant to the requirements of BAAQMD Regulation 2, Permits. These permits are issued in accordance with state law and the District's regulations. The capacities in this table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-403.

Following are explanations of the differences in the equipment list between the time that the facility originally applied for a Title V permit and the permit proposal date:

III. Generally Applicable Requirements

This section of the permit lists requirements that generally apply to all sources at a facility including insignificant sources and portable equipment that may not require a District permit. If a generally applicable requirement applies specifically to a source that is permitted or significant, the standard will also appear in Section IV and the monitoring for that requirement will appear in Sections IV and VII of the permit. Parts of this section apply to all facilities (e.g., particulate, architectural coating, odorous substance, and sandblasting standards). In addition, standards that apply to insignificant or unpermitted sources at a facility (e.g., refrigeration units that use more than 50 pounds of an ozone-depleting compound) are placed in this section.

Unpermitted sources are exempt from normal District permits pursuant to an exemption in BAAQMD Regulation 2, Rule 1. They may, however, be specifically described in a Title V permit if they are considered a significant source pursuant to the definition in BAAQMD Rule 2-6-239.

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 (unless they have been assigned a District permit condition number, in which case they are included as BAAQMD 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.

a. Complex Applicability Determinations:

1. NSPS Subpart J and Fuel Gas Combustion Devices

The A-420 marine terminal thermal oxidizer meets the definition of a fuel gas combustion device in NSPS Subpart J. A-420 abates displaced vapors from marine vessel loading at marine berths S-425 and S-426. The vapors generated by marine loading operations are a fuel gas which is subsequently combusted as specified in 60.101(d). A-420 was put into service in 1990, after the NSPS applicability date of June 11, 1973 in 60.100(b). Therefore, the gas combusted at A-420 is subject to the H2S limit of 230 mg/dscm (0.10 gr/dscf) in 60.104(a)(1), and continuous monitoring is required in accordance with 60.105(a)(3) or (a)(4). These requirements have been added to the permit.

This facility has two flares, the S-296 C-1 flare and the S-398 MP-30 flare. Flares are used only during process upsets and not during routine operations. S-296 was put into service in 1969 and serves as the main refinery flare, potentially flaring gas from several units in the MP-30 Complex: the S-304 and S-305 naphtha hydrotreaters and the S-306 Platforming Unit. The S-398 was put into service in 2000 and serves as a back-up to S-296, potentially flaring emissions from the same process units. Both flares are elevated, steam-assisted flares with water seals. Only S-398 is subject to Subpart J because it was constructed after June 11, 1973. However, because S-398 is required to meet the exemption criteria in 60.104(a)(1), it is not subject to the H2S concentration limit or monitoring requirement. This is typical of situations at oil refineries where the refinery has stated that a flare is used only for upsets and emergencies, and where there is not information to the contrary. The District then proceeds on the assumption that the flare is exempt from the H2S limit of Subpart J. The District's continuing efforts to monitor the applicability of Subpart J to flares should be significantly aided in the future by information generated pursuant to BAAQMD Regulation 12, Rule 11.

Other facility combustion devices were previously determined to be subject or not subject to NSPS Subpart J based on their initial date of operation.

2. Part 63, Subpart CC

Subpart CC is generally applicable to this facility, as shown in Table IV-AA. 63.640(c)(2) is specifically applicable to storage tanks as shown in the tank tables.

V. Schedule of Compliance

A schedule of compliance is required in all Title V permits pursuant to BAAQMD Regulation 2-6-409.10 which provides that a major facility review permit shall contain the following information and provisions:

"409.10 A schedule of compliance containing the following elements:

10.1 A statement that the facility shall continue to comply with all applicable requirements with which it is currently in compliance;

10.2 A statement that the facility shall meet all applicable requirements on a timely basis as requirements become effective during the permit term; and

10.3 If the facility is out of compliance with an applicable requirement at the time of issuance, revision, or reopening, the schedule of compliance shall contain a plan by which the facility will achieve compliance. The plan shall contain deadlines for each item in the plan. The schedule of compliance shall also contain a requirement for submission of progress reports by the facility at least every six months. The progress reports shall contain the dates by which each item in the plan was achieved and an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted."

A Schedule of Compliance is included in the permit for marine wharfs S-425 and S-426 because no monitoring exists to comply with the requirements of 40 CFR 60 Subpart J 60.105(a)(4) to verify the H2S concentration in gas combusted at the A-420 oxidizer that abates emissions from S-425 and S-426.

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.

VII. Applicable Limits and Compliance Monitoring Requirements

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

The tables below contain only the limits for which there is no monitoring or inadequate monitoring in the applicable requirements added in this revision. The District has examined the monitoring for other limits and has determined that monitoring is adequate to provide a reasonable assurance of compliance. Calculations for potential to emit will be provided when no monitoring is proposed due to the size of a source. In all other cases, the column will have "N/A", meaning "Not applicable".

A summary of all monitoring is contained in Section VII, Applicable Limits and Compliance Monitoring Requirements, of the permit. The summary includes a citation for each monitoring requirement, frequency, and type. The applicable requirements for monitoring are completely contained in Sections IV, Source-Specific Applicable Requirements, and VI, Permit Conditions, of the permit.

PM Sources

S# & Description	Federally Enforceable Limit Citation	Federally Enforceable Limit	Monitoring
Gaseous-fired combustion sources: S-36, S-461	BAAQMD 6-301	Ringelmann 1 for more than 3 minutes in any hour	N/A (Note 1)
All sources with particulate emissions	BAAQMD 6-305	no nuisance particulate fallout	None. (Note 2)
Gaseous-fired combustion sources: S-36, S-461	BAAQMD 6-310.3	0.15 grain/dscf @ 6% O2	None. (Note 1)

Note 1: BAAQMD Regulation 6-301 limits visible emissions to no darker than 1.0 on the Ringelmann Chart (except for periods or aggregate periods less than 3 minutes in any hour). Visible emissions are normally not associated with combustion of gaseous fuels, such as natural gas. No monitoring is required for sources that burn gaseous fuels exclusively, per the EPA's June 24, 1999 agreement with CAPCOA and ARB titled "Summary of Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP".

Note 2: Regulation 6-305 is a nuisance prohibition. By definition, this regulation is not violated unless the source is a nuisance. No monitoring is necessary since a violation can only occur if someone is aware of, and complains about, emissions.

Thermal Oxidizer A-420

Condition 4336 for thermal oxidizer A-420, which abates emissions from marine vessel loading operations at berths S-425 and S-426. Permit Condition 4336 requires continuous temperature monitoring to verify compliance with Regulation 8, Rule 44. However, no flowrate monitoring is required to allow calculation of gas residence time. Because A-420 abates displaced vapors from loading operations, the gas flowrate to A-420 is equivalent to the total liquid loading rate at S-425 and S-426. A-420 has a design capacity of 20,000 bbl/hr of displaced vapor. Although Condition 4336 limits loading rate of 25,000 bbl/day (annual average), there is no limit on hourly loading capacity. An hourly loading limit will be added to Condition 4336 to ensure that A-420 is not over-loaded.

A-420 is subject to the requirements of 40 CFR 60 Subpart J 60.105(a)(4) to verify the H2S concentration in gas combusted at A-420. Because no such monitoring is provided, a Schedule of Compliance for S-425 and S-426 has been added to the permit.

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.

IX. Permit Shield:

No changes to permit shields are proposed in this revision.

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>
There have been no changes in the facility's compliance status since the Title V permit was issued on December 1, 2003.

APPENDIX A

GLOSSARY

ACT
Federal Clean Air Act

APCO
Air Pollution Control Officer

API
American Petroleum Institute

ARB
Air Resources Board

BAAQMD
Bay Area Air Quality Management District

BACT
Best Available Control Technology

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

C5
An Organic chemical compound with five carbon atoms

C6
An Organic chemical compound with six carbon atoms

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAPCOA
California Air Pollution Control Officers Association

CEQA
California Environmental Quality Act

CEM
A "continuous emission monitor" is a monitoring device that provides a continuous record of some parameter (e.g. NOx concentration) in an exhaust steam.

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

CO2
Carbon Dioxide

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.

DAF
A "dissolved air flotation" unit is a process vessel where air bubbles injected at the bottom of the vessel are used to carry solids in the liquid into a froth on the liquid surface, where it is removed.

District
The Bay Area Air Quality Management District

DNF
Dissolved Nitrogen Flotation

dscf
Dry Standard Cubic Feet

dscm
Dry Standard Cubic Meter

E 6, E 9, E 12
Very large or very small number values are commonly expressed in a form called scientific notation, which consists of a decimal part multiplied by 10 raised to some power. For example, 4.53 E 6 equals $(4.53) \times (10^6) = (4.53) \times (10 \times 10 \times 10 \times 10 \times 10 \times 10) = 4{,}530{,}000$. Scientific notation is used to express large or small numbers without writing out long strings of zeros.

EFRT
An "external floating roof tank" minimizes VOC emissions with a roof with floats on the surface of the liquid, thus preventing the formation of a VOC-rich vapor space above the liquid surface as the level in the tank drops. If such a vapor space were allowed to form, it would be expelled when the tank was re-filled. On an EFRT, the floating roof is not enclosed by a second, fixed tank roof, and is thus described as an "external" roof.

EPA
The federal Environmental Protection Agency.

ETP
Effluent Treatment Plant

Excluded
Not subject to any District Regulations.

FCC
Fluid Catalytic Cracker

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 (HAP), and Part 72 (Permits Regulation, Acid Rain), and also including limitations and conditions contained in operating permits issued under an EPA-approved program that has been incorporated into the SIP.

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

FR
Federal Register

FRT
Floating Roof Tank

GDF
Gasoline Dispensing Facility

grains
7000 grains per pound

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.

H2S
Hydrogen Sulfide

H2SO4
Sulfuric Acid

Hg
Mercury

IFRT
An "internal floating roof tank" minimizes VOC emissions with a roof with floats on the surface of the liquid, thus preventing the formation of a VOC-rich vapor space above the liquid surface as the level in the tank drops. If such a vapor space were allowed to form, it would be expelled when the tank was re-filled. On an IFRT, the floating roof is enclosed by a second, fixed tank roof, and thus is described as an "internal" roof.

ISOM
Isomerization plant

Lighter
"Lightering" is a transfer operation during which liquid is pumped from an ocean-going tanker vessel to a smaller vessel such as a barge. Like any liquid transfer operation, lightering of organic liquids produces organic vapor emissions.

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 Act and implemented by District Regulation 2, Rule 6.

MOP
The District's Manual of Procedures

MOSC
Mobil Oil Sludge Conversion (licensed technology)

MSDS
Material Safety Data Sheet

MTBE
methyl tertiary-butyl ether

NA
Not Applicable

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

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 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 air pollutants for which the District is classified "non-attainment". Mandated by Title I of the Clean Air Act and implemented by 40 CFR Parts 51 and 52 as well as District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

O2
The chemical name for naturally-occurring oxygen gas.

Offset Requirement
A New Source Review requirement to provide federally enforceable emission offsets at a specified ratio for the emissions from a new or modified source and any pre-existing cumulative increase minus any onsite contemporaneous emission reduction credits. 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
Total 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 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.

Regulated Organic Liquid
"Regulated organic liquids" are those liquids which require permits, or which are subject to some regulation, when processed at a liquid-handling operation. For example, for refinery marine terminals, regulated organic liquids are defined as "organic liquids" in Regulation 8, Rule 44.

SCR
A "selective catalytic reduction" unit is an abatement device that reduces NOx concentrations in the exhaust stream of a combustion device. SCRs utilize a catalyst, which operates at a specific temperature range, and injected ammonia to promote the conversion of NOx compounds to nitrogen gas.

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

SO2 Bubble
An SO2 bubble is an overall cap on the SO2 emissions from a defined group of sources, or from an entire facility. SO2 bubbles are sometimes used at refineries because combustion sources are typically fired entirely or in part by "refinery fuel gas" (RFG), a waste gas product from refining operations. Thus, total SO2 emissions may be conveniently quantified by monitoring the total amount of RFG that is consumed, and the concentration of H2S and other sulfur compounds in the RFG.

SO3
Sulfur trioxide

THC
Total Hydrocarbons (NMHC + Methane)

therm
100,000 British Thermal Unit

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

TRS
"Total reduced sulfur" is a measure of the amount of sulfur-containing compounds in a gas stream, typically a fuel gas stream, including, but not limited to, hydrogen sulfide. The TRS content of a fuel gas determines the concentration of SO2 that will be present in the combusted fuel gas, since sulfur compounds are converted to SO2 by the combustion process.

TSP
Total Suspended Particulate

TVP
True Vapor Pressure

VOC
Volatile Organic Compounds

Units of Measure:

bbl	=	barrel of liquid (42 gallons)
bhp	=	brake-horsepower

btu	=	British Thermal Unit
C	=	degrees Celcius
F	=	degrees Farenheight
f^3	=	cubic feet
g	=	grams
gal	=	gallon
gpm	=	gallons per minute
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inches
max	=	maximum
m^2	=	square meter
min	=	minute
M	=	thousand
Mg	=	mega-gram, one thousand grams
μg	=	micro-gram, one millionth of a gram
MM	=	million
MMBtu	=	million btu
mm	=	millimeter
mm Hg	=	millimeters of Mercury (pressure)
MW	=	megawatts
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

Symbols:

<	=	less then
>	=	greater then
≤	=	less then or equal to
≥	=	greater then or equal to

APPENDIX B

Proposed Changes

1.0 New and Modified Sources in Application 5814 (The evaluation for Application 5814 is included as Appendix F)

1.1 Modified Sources

- S-300, S-304, S-350, S-1002 and S-1003 are modified sources. Of these, S-300 has been issued a Permit to Operate pursuant to Authority to Construct 5814. Therefore, revised conditions for S-300 are effective immediately, while conditions for other sources have a future effectiveness date.
- S-300 modifications have resulted in changes to Table II-A, Table IV-M, Section IV (Conditions 476 (deleted), 21092, 21099) and Table VII-M.
- S-304 modifications have resulted in changes to Table II-A, Table IV-N, Section VI (Conditions 21095, 21099 and 20989) and Table VII-N.
- S-350 modifications have resulted in changes to Table IV-O, Section VI (Condition 383, 21093 and 21099) and Table VII-O.
- S-1002 and S-1003 modifications have resulted in changes to Table II-A, Table IV-U, Section VI (Conditions 21095, 21099 and 20989) and Table VII-U.

1.2 New Sources

S-36, S-460, S-461, S-462 and S-463 are new sources. These sources have been added to Table II-A, Table IV-A.24 and VII-A.24 (S-36), Table IV-A.35 and Table VII-A.35 (S-461), Table IV-N and Table VII-N (S-460), and Table IV-Y and Table VII-Y (S-462 and S-463). Conditions 21094 (S-460), 21096 (S-461), 21097 (S-36) and 21099 (fugitive components) have been added to Section VI. Sources S-460, S-462 and S-463 have been added to Condition 20989.

A-36 and A-461 are new abatement devices and have been added to Table II-B.

S-500 is a new exempt source and has been added to Table II-C.

2.0 Flare Monitoring Conditions

Permit Condition 18255, which includes flare monitoring provisions for visible emissions, has been revised. This condition applies to flares S-296 and S-398. Tables IV-L and VII-L have been revised and the new permit condition text is included in Section VI. The flare capacity for S-296 in Table II-A has been corrected, and this same capacity has been specified for S-398. S-398 acts as a backup for S-398 and the capacity of 845 ton/hr represents the total gas flow produced during the worst-case flaring event represented by a total power failure at the refinery. Also, obsolete "future effectiveness dates" in Table IV-L and VII-L have been deleted.

A discussion of the proposed monitoring is included in Appendix C.

3.0 Regulation 9, Rule 10 Monitoring

Permit Condition 21235 was added to specify the monitoring required for combustion devices subject to Regulation 9, Rule 10. The allowed operating range data in Part 5a of this condition is unspecified, since the applicant has until June 1, 2004 to determine these parameters. Tables IV and VII for the sources listed in the condition have been modified to add these requirements.

A discussion of the proposed monitoring is included in Appendix D.

4.0 Changes Proposed in ConocoPhillips Appeal of Original Permit (The appeal is included as Appendix E)

These issues are each numbered below the same way that they appear in Attachment 3 of the appeal. This attachment is included as Appendix E.

1, 2, 3. The description of tanks S-126, S-257 and S-258 in Table II-A has been corrected from "external floating roof" to "internal floating roof tank with dome roof".

4. Corrected daily capacity for S-319 in Table II-A from 7,500 bbl to 9,600 bbl, and decreased annual throughput limit in Condition 20989 and Table VII-N from 4.32 E6 bbl/yr to 3.51 E 6 bbl/yr to correspond to the revised daily capacity.

5. The "federal enforceability" designation of the individual; requirements of Regulation 9, Rule 10 have been reviewed and corrected for all combustion sources in Tables IV and VII. Affected tables are: IV-A.1 through IV-A.23, IV-A.25, IV-A.26, IV-A.29 through IV-A.33 and VII-A.1 through VII-A.23, VII-A.25, VII-A.26, VII-A.29 through VII-A.33.

6. Citations of 40 CFR 60 Appendix F have been deleted from Table IV for S-43, S-44, S-351, S-371, S-372, S-438 because this QC method does not apply to continuous H2S analyzers, which are the only continuous monitors required for these sources by 40 CFR 60.

7. Citations of 40 CFR 60.693-2 (all subparts) have been deleted because the applicant has indicated that these alternative compliance methods will not be used.

8. The second citation of Condition 7523 in Table IV-K has been corrected to Condition 18680.

9. Corrected name of plan in citation of Condition 20620, Part 2 in Table IV-N.

10. Deleted "daily" from monitoring requirement citation in Condition 383, Part 1b in Table IV-O to correspond to Condition 383.

11. Corrected name of plan in citation of Condition 20620, Part 2 in Table IV-U.

12. Added note to Condition 383 clarifying that the condition applies only to S-300.

13. Comment is no longer valid since the version of Condition 18255 addressed in the comment has been entirely replaced. The new text (Part 7) notes that the NSPS Subpart J requirement applies only to S-398.

14. Added heading to Condition 18680 specifying that this condition applies to S-294.

15. Deleted references to Sources S-53 through S-58 above Parts 1 and 2 of Condition 19488 since these

parts do not apply to these sources.

16. Deleted date in basis for Condition 20620, Part 1 since effectiveness dates should not be included in bases.

17. Corrected annual throughput for S-305 in Condition 20989 from 9.21 E 6 bbl/yr to 9.23 E 6 bbl/yr to correspond to the daily capacity in Table II-A. This same correction was made in Table VII-N.

18. Deleted non-applicable monitoring requirements from Table VII-All Sources.

19. The "federal enforceability" designation of the individual; requirements of Regulation 9, Rule 10 have been reviewed and corrected for all combustion sources IN Tables IV and VII.

20 through 24. Changed individual source firing .limits in Tables VII-A.13 through A.17 to a total for S-15 through S-19 to correspond to Condition 20989, Part A.

25. Replaced "inspection" with "replacement" in each citation of Regulation 8-5-501.2 in Section VII.

26. Deleted citation of floating roof requirements in Subpart QQQ, 60.693-2 in Tables IV-C and VII-C since S-324 has a fixed roof. Also deleted citation of 60.692.3 title in Table IV-C since titles are not normally cited in these tables.

27. Corrected monitoring frequency from D to E in Table VII-O for Condition 383, Part 1b.

5.0 Marine Terminal Thermal Oxidizer

As discussed in Section IV.a.1, the requirements of NSPS Subpart J have been added to the A-420 thermal oxidizer. This addition affects Tables II-B, IV-S and VII-S.

6.0 Other Changes

1. Several combustion sources were shown to have Regulations 1-520.8 and 2-1-403 / 2-1-501 as applicable requirements. These regulations refer to CEMs which are required to be installed by permit conditions. In some cases, although these sources have CEMs, the CEMs are not required by permit conditions, and these citations are inappropriate. These citations have been removed from the following tables: IV-A.8, IV-A.9, IV-A.11, IV-A.12, IV-A.13, IV-A.14, IV-A.15, IV-A.16, IV-A.17, IV-A.19, IV-A.20, IV-A.21, IV-A.22, IV-A.23, IV-A.25, IV-A.26, IV-A.29, IV-A.30, IV-A.31, IV-A.32, IV-A.33 and VII-A.8, VII-A.11, VII-A.12, VII-A.13, VII-A.14, VII-A.15, VII-A.16, VII-A.17, VII-A.32, VII-A.33, VII-A.34.

2. Added footnote 1 to table IV-A.6. This footnote had been inadvertently deleted.

3. Added the basis for Permit Condition 20989 in Tables IV-A.13, IV-A.14, IV-A.15, IV-A.16, IV-A17, IV-A.18, IV-A.19, IV-A.20, IV-A.21, IV-A.22, IV-A.23, IV-A.25, IV-A.26, IV-A.29, IV-A.30, IV-A.31,

IV-A.32, IV-A.33, IV-B,. IV-C, IV-D, IV-E, IV-F, IV-G, IV-K, IV-N, IV-P, IV-S, IV-U, IV-V, IV-W, IV-X, IV-B2, IV-B3, IV-B4, IV-B5, IV-B6, IV-B8, IV-B10, IV-B11, IV-B13, IV-B14, IV-B15, IV-B16, IV-B17, IV-B18, IV-B19, IV-B20.

4. Deleted citations to 9-10-505.1 and 9-10-505.2 in Table IV-A.19. Because 9-10-505 is cited, the sublevels of this requirement do not need to be cited.

5. Added citation of Part D.4 of Permit Condition 1694 for sources S-43 and S-44 in tables IV-A.25 and IB-A.26. These citations were inadvertently omitted.

6. Deleted footnote 1 from table IV-A.30. This footnote does not apply to any of the citations in this table.

7. Added the basis for the citation of Permit Condition 20989, Part B in Table IV-All Sources.

8. In Section VI, the headings to permit conditions which list the facility name and plant number have been deleted since these contain no substantive information and must often be updated to reflect facility ownership or assigned pant number.

9. Citations of Regulation 6-305 (nuisance particulate) have been changed from an "opacity" standard to an "FP" standard, which is more correct. Affected tables are: VII-All Sources, VII-A.32, VII-Q.1, VII-Q.2, VII-U, VII-W, VII-X.

10. Changed the emission limit in the SO2 bubble in accordance with Application 5814. This change affects Tables VII-A.1 through VII-A.26 and VII-A.29 through VII-A.35.

11. Corrected the CEM citation in Regulation 1 from 1-520.8 to 1-520.1 in Table VII-A.6.

12. In some entries in the tables in Section VII, the column for "Type of Limit" was left blank where the same type applied to several entries in succession. In other words, if the type did not change for successive columns, the type entry was left blank. However, this convention was flawed because, in some cases, the first entry in a group with the same type was deleted, leaving several blank entries with an uncertain type. To remedy this situation, all type entries were filled in.

13. Changed the process unit startup/shutdown notification requirements in Condition 20989, Part B. These are non-federally enforceable, state-only requirements. The requirement for notification of unscheduled startup/shutdowns "as soon as feasible" has been deleted because it is too vague. The basic notification requirement remains within 48 hours, but has been expanded to allow notification on the next normal business day as well.

14. Deleted the SIP entries for Rule 8-18 in Tables IV-AB and VII-AB since the current version of the rule has been adopted into the SIP.

15. Deleted the SIP entries for Rule 8-28 in Tables IV-AB and VII-AB since the current version of the rule has been adopted into the SIP.

16. Added list of flares sources to Table II-A for flares S-296 and S-398.

17. Added a maximum hourly loading rate limit and recordkeeping requirement to Condition 4336 for S-425 and S-426.

18. Deleted obsolete "future effectiveness date" (4/1/04) in Tables IV-A.2, IV-A.5, IV-0, IV-Q1, IV-Q2, IV-U, IV-W, IV-X, IV-B1, IV-B2, IV-B3, IV-B5, IV-B21, IV-B22, IV-B23A, IV-B24, IV-B26, IV-B27, IV-B28, IV-B29, IV-B30 and the corresponding tables in Section VII.

19. Added requirements for visible monitoring during tube cleaning in Tables IV-A.2 and IV-A.5 to Tables VII-A.2 and VII-A.5. Also, the stipulation that this monitoring only occur during daylight hours (Condition 1694, Part a.2b) has been deleted.

20. Added a Schedule of Compliance for S-425 and S-426 because no monitoring exists to comply with the requirements of 40 CFR 60 Subpart J 60.105(a)(4) to verify the H2S concentration in gas combusted at the A-420 oxidizer that abates emissions from S-425 and S-426.

21. Deleted federal enforceability designation ("non-federally enforceable") for citations to Regulation 1-522 in the following tables: IV-A.11, IV-A.12, IV-A.13, IV-A.14, IV-A.15, IV-A.16, IV-A.17, IV-A.24, IV-A.25, IV-A.26, IV-A.31, IV-A.32, IV-A.33, IV-A.34, IV-A.35, IV-Q.1, IV-Q.2. Regulation 1-522 contains no substantive requirements; the requirements appear in the subsections to 1-522. Some of these subsections are federally enforceable, while others are not. Therefore, the existing designation of non-federally enforceability is misleading and it is most appropriate for 1-522 to have no federal enforceability designation.

22. Deleted all references to NSPS Subpart A sections in Table IV-L and references to 60.18 in monitoring table VII-L because flare S-398 is not used as a control device to meet an emission standard in any NSPS, and therefore is not subject to any requirement in Section 60.

23. Changed future effectiveness date in Tables IV and VII-A.1 through A.18, A.20 through A.23 and A-25 through A.33 for Condition 21235 from 12/1/04 to 1/1/05. This requirement refers to implementation of new monitoring for compliance with Regulation 9, Rule 10 and was changes so that the monitoring effectiveness date corresponds to the compliance reporting date.

24. Deleted citation of 9-1-302 in Table IV-All Sources, Table VII-All Sources and Table VIII (Test Methods). This facility is not subject to the emission limit in 9-1-302 in accordance with the exemption in 9-1-110 because it complies with the area monitoring requirements of 9-1-110. This citation of 9-1-302 was originally included because, in the event that this area monitoring failed, the facility was considered to automatically be subject to 9-1-302. However, the District has concluded that this is not the case; a monitoring failure is simply a violation of the requirement to maintain the specified monitoring..

7.0 Changes to Permit in Response to EPA Comments in 10/31/03 letter, as updated in 4/14/04 letter from Gerardo Rios to Steve Hill (these letters are included as Appendices K and L)

1. Revised Condition 1694, Part A2.b and A2.c to clarify that the only liquid fuel permitted to be used at S-3 and S-7 is naphtha.

2. The visible monitoring for tube cleaning has been added to Tables VII-A.2 and VII-A.5, and the stipulation that inspections only occur during daylight hours has been removed from Condition 1694, Part A.2b.

3. The federal enforceability status for the CEM Policy and Procedures Manual has been corrected for "no" to "yes" in Tables IV-A.6, IV-A.8, IV-A.11, IV-A.12, IV-A.13, IV-A.14, IV-A.15, IV-A.16, IV-A.17, IV-A.25, IV-A.26, IV-A.31, IV-A.32, IV-A.33, IV-A.34, IV-Q.1 and IV-Q.2.

4. S-388 and S-1007 have been added to Table IV-AA.

5. Citations to 60.482-2(c) and 60.482-7(d) have been added to Table IV-AB.

6. Citation to 63.648(d) has been added to Table IV-AB.

7. A future source testing requirement has been added to Condition 6671.

8. Throughput for S-307 in Table VII-N has been corrected from 1.26 E 7 bbl/yr to 1.39 E 7 bbl/yr to match the cited limit in Condition 20989, Part A.

8.0 Changes to Permit in Response to EPA Comments in 4/14/04 letter from Gerardo Rios to Steve Hill (this letter is included as Appendix L)

1. Added SIP version of 9-1-313 to Table IV-U.

2. Added NSPS Subpart A applicability to thermal oxidizer A-420 in Table II-B.

3. Added Regulation 6-305 applicability to both flares and NSPS Subpart A applicability to flare S-398 Table IV-L.

9. Incorporate Administative Amendment dated May 27, 2004 related to NOx Box and flare monitoring (this Administrative Amendment is included as Appendix M)

1. Future effectiveness dates for all parts of Conditions 18255 and 21235 have been changed to 12/1/04. This change affects and has been incorporated into Tables A.1 through A.18, A.20, A.21, A.22, A.23, A.25, A.26, A.29 through A.33 and L in Section IV, and into Tables A.1 through A.18, A.20, A.21, A.22, A.23, A.25, A.26, A.29 through A.33 and L in Section VII.

10. Changes to Permit in Response to Comments from ConocoPhillips

a. Attachment 1A to ConocoPhillips E-mail dated 12/24/03 from Valerie Uyeda (this e-mail is included as Appendix I)

Comment 6 and 7: Transferred permit shield for API separator from table IX B-1 (which is deleted) to Table IX A-1. Since this is not a subsumed requirement, it should be included in Table IX A-1.

b. Attachment 1 to ConocoPhillips Letter dated 4/13/04 from Phillip Stern (this letter is included as Appendix J)

Comments 1, 3, 5, 7, 9, 11, 13, 14, 16, 18, 19, 20, 21, 22, 23, 24, 25, 27, 29, 31, 33, 35, 40, 41, 44, 64, 66, 70, 71, 72, 73, 80. Corrected O2 monitoring type (either “source test” or “CEM”) in Tables VII- A.1, A.2, A.3, A.4, A.5, A.6, A.7, A.8, A.9, A.10, A.11, A.12, A.13, A.14, A.15, A.16, A.17, A.18, A.20, A.21, A.22, A.23, A.24, A.25, A.26, A.29, A.30, A.31, A.32, A.33, A.34, A.35 to “O2 monitor”, since heater is equipped with an O2 concentration monitor, but not an O2 emissions monitor.

Comments 2, 4, 6, 8, 12, 15, 17, 26, 28, 30, 32, 34, 63, 65. Corrected O2 monitoring frequency to C since heater is equipped with a continuous O2 monitor in Tables VII-A.2, A.3, A.4, A.5, A.7, A.9, A.10, A.18, A.20, A.21, A.22, A.23, A.29, A.30.
Comments 10, 39, 42, 43, 69, 79: Deleted references to “CEM for NOx and O2 (or CO2)” because this is not a true monitoring requirement. The basis for this citation was Regulation 1-520.8, and the purpose was to ensure that the CEM requirements in Reg 1-522 are followed. Because all sources with CEMs

have Reg 1-522 listed as an applicable requirement, this citation is redundant. This affects Tables VII-A-6, VII-A.24, VII-A.25, VII-A.26, VII-A.31 and VII-A.35.

Comment 36: S-36 name has been changed in Tables II-A, IV-A.24 and VII-A.24 to match new identifying name assigned by applicant..

Comment 37: Changed future effectiveness date in Tables IV-A.24 and VII-A.24 from "startup date" to "after initial performance test" for Condition 21097, Parts 3a (abatement requirement) and 3b (emission rate limits) to allow initial adjustment of this new unit.

Comment 38: Changed Condition 21097, Part 3b to indicate that Part 3a and 3b apply after the initial performance test, as described in the response to Comment 37. The condition already indicates this for Part 3b. However, unless it also refers to Part 3a, this startup allowance is not useable. This is a clarification of the obvious intent of the condition rather than an amendment.

Comments 45, 46, 47 and 48: Moved tanks S-107 and S-124 from Tables IV-B18 and VII-B18 to Tables IV-B13 and VII-B13 because these tanks have been retrofitted with superior zero-gap seals.

Comment 53: Corrected citation to Condition 21092 in Table VII-L to refer to Condition 18255.

Comment 54, 55, 56: Sulfur plants S-1001, S-1002 and S-1003 have a future capacity of 271 long ton/day after modification in accordance with permit 5814. The sulfur pits (S-301, S-302 and S-303) have had this future capacity added to Table II-A because the pits handle the molten sulfur from the sulfur plants.

Comment 57, 58 and 59: Sulfur plants S-1001, S-1002 and S-1003 have a future annual throughput of 98,915 long ton/yr after modification in accordance with permit 5814. The sulfur pits (S-301, S-302 and S-303) have had this future throughput added to Condition 20989 because the pits handle the molten sulfur from the sulfur plants..

Comment 60, 61 and 62: Sulfur plants S-1001, S-1002 and S-1003 and sulfur pits S-301, S-302 and S-303 have had a future annual throughput of 98,915 long ton/yr added to Table VII-U as discussed in the response to Comments 57, 58 and 59.

Comment 67: Corrected citation of Condition 21092 to refer to Condition 21093.

Comment 68: References to future Condition 21093 are deleted because this Condition is duplicative of current Condition 383. This affects Table IV-O, Section VI (where Condition 21093 is deleted) and Table VII-0.

Comment 74: Changed name of S-460 from ULSD Hydrotreater to Diesel Hydrotreater.

Comment 75: S-460 has a monthly throughput limit in Condition 21094. This limit obviates the need for an annual limit. Therefore, S-460 has been deleted from Condition 20989 and references to Condition 20989 (related to S-460) have been deleted from Tables IV-N and VII-N.

Comment 76: S-461 name has been changed in Tables II-A, IV-A.35 and VII-A.35 to match new identifying name assigned by applicant..

Comment 77: Changed future effectiveness date in Tables IV-A.35 and VII-A.35 from "startup date" to "after initial performance test" for Condition 21096, Parts 3a (abatement requirement) and 3b (emission rate limits) to allow initial adjustment of this new unit.

Comment 78: Changed Condition 21096, Part 3b to indicate that Part 3a and 3b apply after the initial performance test, as described in the response to Comment 77. The condition already indicates this for Part 3b. However, unless it also refers to Part 3a, this startup allowance is not useable. This is a clarification of the obvious intent of the condition rather than an amendment.

Comment 81: Changed units for S-463 throughput in Condition 20989 from pounds to barrels for consistency with Table II-A. (1,000 bbl/day)(365 day/yr) = 365,000 bbl/yr This change also affects Table VII-Y.

11. Changes to Permit/SOB in Response to EPA Comments on EPA Review Version (December, 2004)

1. 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. The sources in Tables IV-M, IV-N, IV-O, IV-P and IV-V, and Tables VII-M, VII-N, VII-O, VII-P and VII-V are subject to Regulation 8, Rule 10 and have 8-10-401.2 indicated as federally enforceable monitoring. 8-10-501 and 8-10-502 (2004 rule) have been added in Section VII tables as federally enforceable monitoring requirements. The 2004 version of Regulation 8, Rule 10 has been added to Table III ("Generally Applicable Requirements"); this table already included the 1983 SIP version of this rule.

2. Added explanatory text to Section C.I of the Statement of Basis, as well as standard permit conditions I.J.4 through I.J.8 to the permit to address U.S. EPA comments.

APPENDIX C

Flare Monitoring

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. 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.

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 1 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 2 requires recordkeeping to demonstrate compliance with Part 1.

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 5 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.

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.

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 7** imposes a condition on these flares to assure compliance with the exemption criteria. The same prohibition found in Part 7 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 7 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 and 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 Reg 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 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 refinery has no thermal oxidizers subject to residence time requirements.

APPENDIX D

Regulation 9, Rule 10 Monitoring

"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 MM BTU 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/MM BTU (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 MM BTU 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.

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 3a 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.

APPENDIX E

Attachment 3 to ConocoPhillips' Appeal of Initial Major Facility Permit

APPENDIX F

Evaluation for Application 5814

Engineering Evaluation

ConocoPhillips Company, Plant 16

Ultra Low Sulfur Diesel / Strategic Modernization Project

Application 5814

Prepared By: Julian Elliot, Senior Air Quality Engineer

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1.0 BACKGROUND

ConocoPhillips Petroleum (ConocoPhillips) has submitted an application to install new sources and modify existing sources and processes at the San Francisco Refinery in Rodeo. This project will accomplish three objectives: 1) allow production of ultra low sulfur diesel (ULSD) through increased hydrotreating, 2) allow the refinery to process a greater range of crude oils, and 3) maintain gasoline production level at current levels while increasing diesel production and crude processing capacity. After modifications are complete gasoline production may increase by a nominal amount of approximately 500 bbl/day, while gas oil and diesel production are expected to increase by approximately 4,000 bbl/day each, and crude oil processing capacity will increase by 10,000 bbl/day. [Gas oil is a generic term for a medium distillate with a boiling point above 350 degrees F, which is used as an intermediate feedstock.]

ULSD is defined as diesel fuel with a sulfur content of no more than 15 ppmw. The use of ULSD fuel in motor vehicles is required by existing federal regulations, and expected state regulations, by June 1, 2006. ConocoPhillips expects to produce ULSD as much as 2 years in advance of this deadline through this project.

The additional crude oil processed at the refinery will come primarily from the Central Valley of California. This crude has a relatively high sulfur content.

In addition to the production of ULSD (at higher levels than the current production of low-sulfur diesel), the proposed project will result in increased production of butane, fuel gas, sulfur and coke. There will be no net increase in water consumption or wastewater discharge although the composition of discharged water may change as discussed in the project EIR. The existing facility steam/power plant will meet additional electrical requirements.

ConocoPhillips has estimated increased sour gas production of up to 1.7 million standard cubic feet per day, as well as increased production of sour water. The systems which remove sulfur compounds from sour gas and sour water streams will be upgraded to increase their removal capacity, as will the sulfur plants which convert these sulfur compounds to elemental sulfur (see Sections 2.4, 2.5 and 2.6). Nonetheless, increased sulfur compound emissions are a concern, especially SO_2 emissions resulting from increased combustion of fuel gas (since increased sour gas production will ultimately result in higher volumes of fuel gas) or from higher levels of sulfur compounds in fuel gas. This concern is addressed by the existing sulfur bubble in Condition 1694. This condition requires analysis of sulfur compounds in fuel gas three times per day, and includes an SO_2 emission limit from fuel gas combustion for all refinery combustion sources except the steam/power plant. The SO_2 bubble ensures that increased processing of crude oil, and the processing of crude stocks containing higher sulfur levels, will not result in SO_2 emissions beyond permitted levels.

2.0 NEW AND MODIFIED SOURCES

This section addresses the new sources, modified sources and operational changes which may result in emission increases. Where an emission increase is identified, the increase is quantified in Section 3.0 ("Emissions Calculations").

In addition to the new and modified sources discussed below, the project EIR quantifies emission increases to existing sources resulting from operational changes caused by the proposed project. Specifically, existing tanks will undergo service changes which will result in a net reduction in emissions (EIR, Appendix C, Section A.7), and existing heaters will undergo firing duty changes and changes in the level of sulfur compounds in fuel gas (EIR, Appendix C, Section A.3) which will result in a net emission increase. These emission changes are summarized in the project EIR (Appendix C, Table A-22). These operational changes and resulting emission increases are within the scope of existing permits and therefore do not represent source "modifications" as described in Regulation 2-1-234.

2.1 New S-460 ULSD Hydrotreater and Heater

S-460 is a new ULSD hydrotreater (Unit 250). A hydrotreater reacts petroleum compounds with hydrogen in the presence of a catalyst to remove sulfur from the petroleum in the form of H2S gas, and to hydrogenate unsaturated compounds. S-460 will be the primary mechanism for removal of additional sulfur to meet ULSD standards. S-460 will hydrotreat diesel cuts from the various processing units, including the S-350 crude unit (Unit 267) and the S-300 crude/coker (Unit 200).

S-460 will have a capacity of 35,000 bbl/day, and will consist of two towers, both about 14 feet in diameter, with heights of about 70 feet and 85 feet. S-460 will include a new 50.2 MM BTU/hr charge heater which will be permitted as S-461, and which will be abated by the A-461 SCR system. S-461 will burn refinery gas, with natural gas as a backup fuel. In addition to a reduced-sulfur diesel stock, S-460 will produce fuel gas and a naphtha stock. S-460 will utilize an existing, but unused, refinery cooling tower (S-500) to provide required cooling water.

2.1.1 New ULSD Hydrotreater Emissions

Processing units like S-460, which have no discrete emission points are not charged emissions directly. Instead, emissions are quantified for fugitive components (which are not assigned source numbers) and for associated combustion sources (which are permitted as separate sources). Fugitive emissions are considered in Section 2.10.

The ULSD Hydrotreater will have the capability of being purged with nitrogen during removal from service. The vaporizer will use indirect contact with steam and ambient air to vaporize the liquid nitrogen. Thus, the nitrogen vaporizer is not a combustion source and will not be considered further in this evaluation.

2.1.2 New ULSD Hydrotreater Charge Heater (S-461) Emissions

Emissions from the new S-461 Heater are quantified in Section 3.1.1.

2.2 S-304 Hydrotreater Service Change

The new S-460 hydrotreater will replace the existing S-304 diesel hydrotreater (Unit 229) in diesel service. S-304 will be switched to naphtha hydrotreating service, to supplement the naphtha hydrotreating capacity of the existing S-305 hydrotreater (Unit 230). S-304 will be modified to treat light naphtha streams, while S-305 will treat medium naphtha streams. Together, the two naphtha hydrotreaters will allow additional removal of sulfur from gasoline feedstocks. S-304 will be modified by replacement of the hydrotreater reactor and by modification of heat exchangers, and will have a naphtha processing capacity of 12,198 bbl/day. Converting S-304 to naphtha service will allow the retirement of one S-305 distillation tower.

2.2.1 S-304 Hydrotreater Service Change Emissions

Processing units like S-304, which have no discrete emission points are not charged emissions directly. Instead, emissions are quantified for fugitive components (which are not assigned source numbers) and for associated combustion sources (which are permitted as separate sources). Fugitive emissions are considered in Section 2.10.

2.3 Crude Unit and Crude/Coker Unit and Heater Modifications

Currently, crude oil may be processed at either the S-350 crude unit (Unit 267) or the S-300 crude/coker (Unit 200), with S-350 handling light foreign crudes and S-300 handling heavy or sour crudes, as well as semi-refined crude stocks. S-350 consists of a desalter followed by vacuum and atmospheric distillation towers, while S-300 consists of vacuum and atmospheric distillation towers followed by a delayed coker. Currently, bottoms streams from both the S-350 and S-300 distillation towers are processed as parallel feedstreams at the S-300 coker. The proposed units will modify this flow by processing the S-350 bottoms at the S-300 vacuum tower, with the S-300 bottoms continuing to the S-300 coker.

Currently, Condition 476 limits the feed rate at S-300, while Condition 383 limits the feed rate at S-350. No change has been proposed to the feed rate limit for S-350 (33,000 bbl/ highest day, 30,000 bbl/annual average day). The total feed rate for S-300 is proposed to increase from 56,000 bbl/highest day (52,000 bbl/annual average day) to 81,000 bbl/highest day. This total increase of 25,000 bbl/day is expected to consist of the following:

Increased S-300 feedstream	Feed Rate (bbl/day)
imported crude oil	10,000
imported diluent	6,000
facility bottoms streams	9,000
Total	**25,000**

The proposed modifications include internal modification of S-350 to allow the unit to process a greater range and increased amount of crude oil. Also, the vacuum and atmospheric distillation towers at S-300 are at the end of their service lives and will be replaced with new towers with increased capacity. The secondary distillation tower will be about 12.5 feet in diameter and 125 feet tall, while the vacuum tower will be about 15 feet in diameter and 58 feet tall.

A new 82.1 MM BTU/hr process heater will be added to S-300. This heater will be permitted as S-36 and will be abated by the A-36 SCR system. S-36 will be used to heat the feed stream to the crude unit vacuum tower. S-36 will burn refinery gas, with natural gas as a backup fuel.

Two operational changes involve the flow of diesel streams and wastewater from S-350. Currently, diesel streams from S-350 flow directly to blending units. As noted above, diesel streams are proposed to be treated at the new S-460 hydrotreater. However, these diesel streams may flow to storage tanks from S-350, prior to treatment at S-460. Existing tankage will be used for this purpose. Wastewater from S-350 currently flows directly to the refinery sewer system. After modification, S-350 wastewater will flow to a storage tank, and then will be processed at the sour water strippers and the selenium plant prior to discharge into the sewer system. Existing tankage will be used for intermediate storage of wastewater. Storage tanks are discussed in Section 2.13.

2.3.1 Crude Unit and Crude/Coker Unit Modification Emissions

Processing units like S-350 and S-300, which have no discrete emission points are not charged emissions directly. Instead, emissions are quantified for fugitive components (which are not assigned source numbers) and for associated combustion sources (which are permitted as separate sources). Fugitive emissions are considered in Section 2.10.

Increased coker activity will result in increased production of coke (186 ton/day). Also, truck traffic associated with coke removal will increase about 17%, from 48 truckloads per day to 56 truckloads per day. Emissions from truck traffic are considered in Section 2.14. Emissions from coke handling are quantified in Section 3.1.6.

2.3.2 Crude Unit Vacuum Tower Heater (S-36) Emissions

Emissions from the new S-36 Heater are quantified in Section 3.1.2.

2.4 Amine Scrubbers / Strippers

*H2S-rich gas from hydro*treaters and other sources is currently processed at two amine scrubbers. The scrubbers use diglycolamine (DGA) as a solvent to scrub H2S from these gases. Then, the H2S-rich scrubbing solution is processed at three amine strippers where heat is used to drive the H2S from the amine solution. The stripped H2S-rich gas is treated at the refinery sulfur recovery plants where H2S is converted to elemental sulfur.

The proposed modifications will not affect the two amine scrubbers. However, the heat exchangers in two of three amine strippers will be replaced to increase the effectiveness of the strippers.

2.4.1 Amine Scrubbers / Strippers Emissions

Processing units like the amine strippers and scrubbers, which have no discrete emission points are not charged emissions directly. Instead, emissions are quantified for fugitive components (which are not assigned source numbers). Fugitive emissions are considered in Section 2.10.

The two refinery hydrogen plants will provide steam required by the amine strippers. Specifically, heaters S-14 and S-438 will produce this steam. All facility steam sources, including S-14 and S-438 in Condition 1694, have existing permit conditions limiting fuel use. Therefore, increased production of steam will not be considered a modification and an emission increase will not be quantified. It should be noted that some aspects of the project, most notably the removal from service of a distillation tower at S-305 will result in substantial steam savings.

2.5 Sulfur Recovery Plants S-1002, S-1003

The refinery currently operates three sulfur recovery plants that use the Claus process to convert sulfur-containing acid gas to elemental sulfur. Acid gas is produced by hydrotreaters, the hydrogen plants, fuel gas treatment unit and butane treatment units. The first step of the conversion process involves the thermal reaction of one third of the H2S with oxygen to form SO2.

This thermal reaction occurs at temperatures ranging from 1,800 to 2,800 degrees F, with the reaction furnace heated by burners. The oxygen is typically provided by introducing air to the reaction chamber. However, the process can be made more efficient by using pure oxygen instead of air. The thermal reaction equation is:

$$2H_2S + 3O_2 \rightarrow 2SO_2 + 2H_2O + \text{heat of reaction}$$

Because air is only 21% oxygen by volume, with the balance nitrogen and traces of argon, the substitution of oxygen for air dramatically reduces the volume of reaction gas, or allows the processing of more acid gas at the same furnace heat load and size. The proposed modifications include the conversion of two of the sulfur recovery plants (S-1002, S-1003) to use pure oxygen. Sulfur plant S-1001 will not be modified. Liquid oxygen will be imported by tanker truck and stored onsite. This modification is expected to increase the sulfur recovery capacity by 15% at each of the modified plants, without increasing the fuel requirements for the thermal reaction at these plants.

The sulfur plant has a daily capacity of 245 long tons of sulfur per day (nominal capacities of 70, 75 and 100 long ton/day at S-1001, S-1002 and S-1003, respectively). [Note: Sulfur plant capacity is expressed in "long" or "metric" tons. The equivalent nominal capacities of each sub-plant in "short" or "U.S." tons are 78, 84 and 112 short ton/day, or a total capacity of 274 short ton/day.] The sulfur plant will require an increased sulfur-removal capacity of about 25 long ton/day (expressed as sulfur) to handle the increased sulfur load from the increased crude feed rate, additional hydrotreating of diesel, and the processing of alternate crude stocks. A 15% increase in capacity at S-1002 and S-1003 represents a total increase of over 26 long ton/day. Thus, overall capacity would increase from 245 long ton/day to 271 long ton/day.

The oxygen vaporizers will use indirect contact with ambient air to vaporize the liquid oxygen. Thus, these vaporizers are not combustion sources and will not be considered further in this evaluation.

In addition to molten sulfur, the sulfur plants produce a tailgas stream that contains residual H2S. The tailgas stream from each sulfur plant is treated at a dedicated treatment plant that uses the Beavon Stretford process. The Beavon Stretford process uses a catalytic reaction to convert both H2S and SO2 in the tailgas to H2S, which is then removed in a liquid absorber. The absorbing liquid stream undergoes a reaction to convert H2S to elemental sulfur.

2.5.1 Sulfur Recovery Plants S-1002, S-1003 Emissions

The exhaust stream from each Beavon Stretford treatment plant contains a residual amount of H2S. If the increased processing of crude or the increased sulfur load increases the residual H2S concentration and/or increases the volume of the exhaust stream(s), then the overall emissions of H2S would increase. As discussed above, ConocoPhillips has indicated that the use of pure oxygen at the two modified sulfur plants will increase the capacity of these plants by about 15%. This capacity increase is estimated to exceed the actual increase in sulfur loading. However, if the two plants were loaded to capacity, approximately 15% more sulfur would be produced and 15% more H2S and SO2 would remain in the tailgas. However, the volume of tailgas would decrease because the replacement of air with oxygen would eliminate the nitrogen in the combustion air. Therefore, emissions of H2S and S02 are not expected to increase at these sources.

Sulfur plants S-1001, S-1002 and S-1003 currently have separate implied throughput limits of 70, 75 and 100 long tons/day, respectively, based on data forms submitted to the District. In reality, these limits represent nominal capacities for each plant. In the event that a single plant is removed from service, the remaining plants could exceed these nominal capacities. However, the current total capacity of the three plants is equivalent to the total of these nominal capacities: 245 long tons/day. Each sulfur plant discharges molten sulfur to an associated sulfur pit (S-301, S-302, S-303). The three pits are interconnected, and all share a common truck loading point. Thus, the sulfur pits are most accurately described as also having a total capacity of 245 long tons/day. The proposed modifications to S-1002 and S-1003 are expected to increase the nominal capacity of each 15%. The overall increase in sulfur capacity would be:

(75 + 100) long tons/day (0.15) = 26 long ton/day

Thus, the new overall sulfur production limit would be:

(245 + 26) long ton/day = 271 long ton/day

2.6 Sour Water Strippers

Sour water contains sulfur compounds or ammonia, and is produced whenever steam is condensed in the presence of gases containing these compounds, including hydrotreating and sulfur plant tailgas treatment (both discussed above). Sour water is odorous and must be treated to remove sulfur compounds and ammonia prior to discharge into the refinery sewer system. The refinery currently operates two sour water strippers with a combined processing capacity of 280 gallons per minute. The proposed modifications include the addition of a new stripper with a capacity of 230 gallons per minute. The new stripper would be used with one of the existing strippers, to provide an increased processing capacity of about 360 gallons per minute. The other existing stripper would be available as a backup, but would not normally be in service.

Sour water strippers use steam to strip contaminants from sour water into a gas phase, that is condensed to produce a contaminant-rich, non-condensable gas stream and a condensate stream. Condensate liquid is recycled to the stripper, while the non-condensable stream is vented to a sulfur recovery plant.

2.6.1 Sour Water Stripper Emissions

The sour water strippers have no discrete emission points. Fugitive emissions are considered in Section 2.10.

The two refinery hydrogen plants will provide steam required by the sour water strippers. Specifically, heaters S-14 and S-438 will produce this steam. All facility steam sources, including S-14 and S-438 in Condition 1694, have existing permit conditions limiting fuel use. Therefore, increased production of steam will not be considered a modification and an emission increase will not be quantified. It should be noted that some aspects of the project, most notably the removal from service of a distillation tower at S-305, will result in substantial steam savings.

Sulfur compounds in the non-condensable gas stream are included in the emission increase from the sulfur recovery plant (discussed above).

2.7 Butane and Fuel Gas Caustic Treatment

The proposed modifications, as a result of the increased processing of crude stocks, will result in greater production of organic gases. One of these gases, butane, is a saleable product. Other gases are used as fuel for refinery combustion sources. Both butane and fuel gases require treatment to reduce sulfur content prior to sale or combustion onsite. ConocoPhillips has proposed to install two additional gas caustic scrubber systems, one to treat butane gas at the butane distillation unit (S-463) and one to provide additional treatment of fuel gas from the fuel gas center (S-462) prior to combustion at S-36 and S-461. Each system will include a new caustic scrubber, and both systems will share a caustic solution stripper (to recycle caustic solution) and a storage tank for caustic solution.

2.7.1 Butane and Fuel Gas Caustic Treatment Emissions

The butane and fuel gas treatment systems have no discrete emission points. Fugitive emissions are considered in Section 2.10.

The two refinery hydrogen plants will provide steam required by the two new caustic strippers. Specifically, heaters S-14 and S-438 will produce this steam. All facility steam sources, including S-14 and S-438 in Condition 1694, have existing permit conditions limiting fuel use. Therefore, increased production of steam will not be considered a modification and an emission increase will not be quantified. It should be noted that some aspects of the project, most notably the removal from service of a distillation tower at S-305, will result in substantial steam savings.

In addition to treated butane and fuel gas streams, the caustic treatment systems produce a sour gas stream (the non-condensable overhead stream from the caustic recycling stripper) that is processed at the sulfur recovery plants. Indirect emissions of sulfur compounds from this stream are included in the emission increase from the sulfur recovery plant (discussed above).

2.8 Wastewater Treatment System

The existing wastewater treatment facility has a capacity of approximately 10 MM gal/day. Average refinery wastewater production is about 2.5 MM gal/day. Since the project is not designed to increase wastewater discharge, the existing facility will continue to have excess capacity and is not proposed to be modified. No changes are proposed to existing permit condition limits associated with the wastewater treatment facility.

2.8.1 Wastewater Treatment System Emissions

Because there will be no physical modification to the wastewater treatment facility, and because existing throughput limits in Condition 1440 will not be modified, no emission increase will be quantified.

2.9 S-500 ULSD Cooling Tower (Exempt)

An existing facility cooling tower, currently unused, is proposed to be renovated and used to cool and condense products at the proposed S-460 ULSD hydrotreater. The cooling tower will handle only water provided by the local water utility and pumped through S-460 heat exchangers, and will not directly handle process water. The tower will have a circulation rate of 11 MM gal/day.

Regulation 2-1-128.4 provides a permit exemption for cooling towers which do not perform evaporative cooling of process water or water from barometric jets or barometric condensers. Sources which are exempt from permits must comply with the requirements of Regulation 2-1-319. These requirements include an emission rate less than 5 tons per year. Also exempt sources must not be subject to Regulations 2-1-316 (Toxic Air Contaminants or Hazardous Air Pollutants), Regulation 2-1-317 (Public Nuisance) or Regulation 2-1-318 (Hazardous Substances).

The application includes an estimate of particulate emissions in accordance with the procedure in Chapter 11.4 of the District Permit Handbook Chapter for cooling towers. The estimated emissions are 3.75 ton/yr of PM10. Therefore, this cooling tower is exempt from permit requirements and will not be considered further in this evaluation. Thus, Regulation 2-1-319 is satisfied.

Because this cooling tower will not handle process water, the only potential source of toxic emissions is from water-quality additives. This tower will use sodium hypochlorite as an additive. The project EIR (response to comment C4-76) estimated a chloroform emission rate of 14.5 lb/yr, based on the amount of sodium hypochlorite that will be added to the cooling tower water. This is less than the chloroform trigger level of 36 lb/yr. Thus, no risk screening is required and the requirements of Regulation 2-1-316 do not apply. None of the compounds listed in Regulation 2-1-318 will be emitted, so the requirements of this regulation do not apply.

The nuisance requirements of 2-1-317 will be assumed to not apply since cooling towers are not typically the source of nuisance complaints.

2.10 Fugitive Components

Fugitive sources of organic emissions include valves, flanges, connectors, pumps and other devices that may leak organic gases or liquids. New process units and auxiliary equipment will include the following fugitive components (from application Appendix B-1). These equipment counts are estimates pending construction and may be modified as described in the proposed permit conditions:

SOURCE	COMPONENT COUNTS					
	STREAM	VALVES	PUMPS	CONNECTORS	FLANGES	COMPRESSORS
S-460 ULSD Hydrotreater	Gas	605	0	210	140	7
	l liquid	323	4	138	92	0
	h liquid	1081	7	387	258	0
S-304 Naphtha Hydrotreater	Gas	605	0	210	140	7
	l liquid	323	4	138	92	0
	h liquid	1081	7	387	258	0
S-462 Fuel Gas Caustic Treatment	Gas	696	0	1044	696	0
	l liquid	0	2	3	2	0
	h liquid	0	0	0	0	0
S-463 Butane Caustic Treatment	Gas	696	0	1044	696	0
	l liquid	0	2	3	2	0
	h liquid	0	0	0	0	0

2.10.1 Fugitive Component Emissions

Fugitive emissions are quantified in Section 3.1.3.

2.11 Relief and Flare System

The new and modified refinery units will connect all new relief devices to the existing relief and blowdown system. This system has a gas recovery capacity of 200,000 scf/hr, which is set by the amount of compressor capacity available. If this gas volume is exceeded, excess gas would be diverted to one of the 2 existing refinery flares for release. No additional flares will be installed, and no modification will be made to the existing flares.

Flaring is not a necessary step during unit shutdowns or complete refinery shutdowns, and flaring usually does not occur during these events. However, flaring may occur during unit upsets, and these upsets are more likely to occur during a unit startup than during a shutdown.

Although any process unit, including the new ULSD hydrotreater, is subject to upset conditions that could result in an unplanned shutdown, the refinery modifications have been designed to not increase the flaring load during the design event for the facility flares (a total power outage). In the event of an unplanned shutdown, the new hydrotreater has been designed to close its process isolation valves and stop heat input from its heaters, with no need to relieve internal pressure. Also, the new secondary distillation tower at S-350 will have a higher pressure rating (75 psig) than the current tower (47 psig), although the normal operating pressure of 10 psig will not increase. Thus, this secondary tower will be less likely to experience an overpressure event. Finally, the distillation tower to be removed from S-305 will no longer be a potential cause of flaring.

2.11.1 Relief System Emissions

Because this facility does not perform routine flaring, and because routine flaring will not result from any of the proposed new or modified sources, no emission increase will be quantified from flaring.

2.12 Steam / Power Plant

Although the proposed project will result in an increase in electrical demand, that demand will be satisfied by the existing refinery steam/power plant. The steam/power plant currently operates at an average availability of 95%, providing all the refinery electrical demand and exporting approximately 7 MW of surplus power. After the proposed modifications, the average refinery electrical load will increase by about 5.5 MW, such that surplus power will drop to about 1.5 MW. No increase is proposed to the fuel consumption limits at the existing turbines, and no additional emissions are expected from the steam/power plant.

2.13 Storage Tanks

2.13.1 Inorganic Storage Tanks

New tanks will be constructed to store liquid oxygen for use in the modified sulfur plants, and liquid nitrogen for use in purging new process units. Liquid oxygen and nitrogen tanks are exempt from permit requirements in accordance with Regulation 2-1-123.3.1. Therefore, these tanks will not be considered further in this evaluation.

Caustic and amine storage tanks will be constructed at the proposed butane and fuel gas caustic treatment systems. These inorganic storage tanks are exempt from permit requirements in accordance with Regulation 2-1-123.1 and 2-1-123.2. Therefore, these tanks will not be considered further in this evaluation.

Wastewater from S-350 currently flows directly to the refinery sewer system. After modification, S-350 wastewater will flow to a storage tank, and possibly to pre-treatment, prior to discharge into the sewer system. Existing tankage will be used for this purpose. The storage of process water, including sour water, is typically exempt from permit requirements in accordance with Regulation 2-1-123.2. Therefore, storage of this wastewater will not be considered further in this evaluation.

2.13.2 Organic Storage Tanks

No new organic storage tanks are proposed for this project. However, some existing tanks will experience service changes resulting from increases in crude oil processing, increases in production of gasoline, diesel and gas oil, and from operational changes.

First, the proposed increase in crude processing (10,000 bbl/day) will result in an increase in utility at existing crude tanks. Most of this additional crude oil will be sour crude. Sour crude has higher levels of sulfur, nitrogen and metals than sweet crude. However, sour crude is not sufficiently different from sweet crude that the storage of sour crude in a tank which had previously stored sweet crude should be considered a modification of the tank (assuming that additional control requirements in Regulation 8, Rule 5 are not triggered). This is consistent with previous treatment of tanks at this facility and other refineries, where no distinction is made between sweet and sour crude when permitting a crude oil storage tank. Further, because the increased crude processing will be accommodated without modification of storage tank pumps or other auxiliaries, no modification will be considered to result from the increased processing.

Second, nominal increases in gasoline production and more significant increases in gas oil and diesel production will result in an increase in utility at existing tanks used to store these materials. Each of these is an existing product, and storage is available for each. Because increased storage demands will be accommodated without modification of storage tank pumps or other auxiliaries, no modification will be considered to result from the increased storage of these materials. Gas oil and diesel oil tanks are typically exempt from permit requirements based on their low vapor pressures.

Finally, diesel streams from the S-350 crude unit will be combined and held in storage tanks, prior to treatment at S-460. Currently, these streams are not stored prior to hydrotreating and final blending. Existing tanks S-179 and S-180 will be used to store these diesel streams. These tanks are currently designated as exempt sources, in accordance with District Regulation 2-1-123.3.2 (initial boiling point greater than 302 degrees F and greater than 180 degrees F over storage temperature). The diesel stocks that will be stored are expected to continue to satisfy this exemption criteria. Thus, tanks S-179 and S-180 will not be considered further in this evaluation.

The project EIR (Appendix C, Section A.7) notes that there will be an overall decrease in emissions from storage tanks because of changes in existing tank utilization.

2.14 Shipping Activity

The proposed modification will result in additional vehicle traffic at the refinery, including trucks and marine vessels. This traffic consists of the categories listed below.

COMMODITY	INCREASED TRAFFIC	VEHICLE
RAW MATERIAL DELIVERY:		
LIQUID OXYGEN	365 TRIP/YEAR	TRUCK
LIQUID NITROGEN	37 TRIP/YEAR	
SPENT CAUSTIC	37 TRIP/YEAR	
FEEDSTOCK ADDITIVES	183 TRIP/YEAR	
OTHERS	110 TRIP/YEAR	
PRODUCT SHIPPING:		
PETROLEUM COKE	2,716 TRIP/YEAR (TO MARINE TERMINAL)	TRUCK
MOLTEN SULFUR	1,207 TRIP/YEAR	
PRODUCT SHIPPING:		
GAS OIL	4 TRIP/YEAR	BARGE
PETROLEUM COKE	1 TRIP/YEAR	FREIGHTER

The bulk of additional raw materials and additional products will be shipped by pipeline, including the additional 10,000 bbl/month of feed crude oil, as well as all additional gasoline and diesel fuel exports. The only petroleum liquid products that will not be shipped by pipeline are gas oil and petroleum coke. Gas oil will be shipped via barge. The barges that will be used will have a capacity of 80,000 barrels and will be driven by a single tugboat. Petroleum coke will be shipped via freighter. The freighters that will be used will have a capacity of 60,000 dead weight tons and will be guided by two tugboats. Emissions from marine carriers handling are quantified in Section 3.1.4.

In accordance with the definition of a “facility” in Regulation 2-2-215, facility emissions do not include those from motor vehicles (such as truck engines), but do include emissions from “cargo carriers" such as marine vessels, and particulate emissions from truck traffic on refinery roads, which are all paved.

Pipeline operations are not considered in this evaluation since no expansion of pipeline infrastructure is proposed.

2.14.1 Increased Cargo Carrier Emissions

Emissions from the increased marine vessel activity are quantified in Section 3.1.4.

2.14.2 Increased Truck Traffic Emissions

Emissions of particulate matter raised by additional truck traffic on refinery roads are quantified in Section 3.1.5.

3.0 EMISSIONS CALCULATIONS

3.1 Annual Average Emissions:

Annual average emissions are calculated to determine the facility cumulative increase, the required amount of emission offsets and the applicability of PSD requirements.

3.1.1 New ULSD Hydrotreater Charge Heater (S-461)

3.1.1.1 Assumptions and Emission Factors

The following assumptions will be used to estimate S-461 emissions:

- fuel: refinery fuel gas (natural gas backup)
- proposed utility: 100% (8,760 hr/yr)
- maximum firing rate: 50.2 MM BTU/hr
- nat. gas heat value: 1,050 BTU/scf (BAAQMD standard value)
- fuel gas heat value: 1,516 BTU/scf HHV (ConocoPhillips)
- annual fuel use: 439,800 MM BTU
- abatement device: selective catalytic reduction (SCR)
- ammonia slip from SCR: 10 ppmv @ 3% O2

- emission factors (controlled):

POLLUTANT	EMISSION FACTOR	SOURCE
NOx	10 ppmvd @ 3% O2	BAAQMD BACT Workbook, Determination 94.3.1 (8/12/94)
CO	50 ppmvd @ 3% O2	BACT Determination, Section 6.1
POC	5.5 lb/MM ft3	U.S. EPA AP-42 Table 1.4-2 for natural gas
SO2	45 ppmv total reduced sulfur (TRS) in fuel	BACT Determination, Section 6.1

	gas	
PM10	7.6 lb/MM ft3	U.S. EPA AP-42 Table 1.4-2 for natural gas
NPOC	Negligible	U.S. EPA AP-42

Notes:

1. Ammonia emissions are quantified in Section 5.0 (Toxic Risk Management)
2. POC and PM10 emission factors are taken from AP-42 data for natural gas.
3. a CO emission factor is conservatively used, even though S-461 is subject to a tiered exhaust limit for CO which sets a limit of 28 ppmv at firing rates of 50% of more, and a limit of 50 ppmv at firing rates less than 50%.

Convert NOx, CO and SO2 "ppm" to "lb/MM BTU":

For NOx and CO, this conversion may be done using the EPA "Fd" factor from 40 CFR Part 60 test methods, for example Method 19, Table 19-1-F. Fd is the ratio of the volume of dry flue gas to the heat value of the fuel used to produce the flue gas. Fd for natural gas is 8,710 dscf/MM BTU (from Method 19), Fd for refinery fuel gas is 8,831 dscf/MM BTU (from application Appendix B-2). Emission factors will be based on refinery fuel gas since this yields the higher emission factor. The conversion assumes that the flue gas is ideal (since flue gas molar volume is assumed to be 359 cf/lbmole) which is a valid assumption because of the relatively high temperature and low pressure of the flue gas. The conversion includes a correction of the pollutant concentrations from 3% O2 to 0% O2 (in accordance with District procedure ST-13A) since the flue gas volume assumes stoichiometric combustion (zero excess air and O2).

NOx (molecular weight 46.01):

(10/MM)(20.95%-0%/(20.95%-3%))(8,831 ft3/MM BTU)

(lbmole/359 ft3)(46.01 lb/lbmole) = **0.013 lb/MM BTU**

CO (molecular weight 28.01):

(28/MM)(20.95%-0%/(20.95%-3%))(8,831 ft3/MM BTU)

(lbmole/359 ft3)(28.01 lb/lbmole) = **0.023 lb/MM BTU for 28 ppmv**

(50/MM)(20.95%-0%/(20.95%-3%))(8,831 ft3/MM BTU)

(lbmole/359 ft3)(28.01 lb/lbmole) = **0.040 lb/MM BTU for 50 ppmv**

For SO2, the applicable emission limit actually addresses the concentration of total reduced sulfur (TRS) in any sulfur compounds in the fuel gas, and not the concentration of SO2 in the exhaust gas. Therefore, the TRS concentration limit must be converted to an equivalent SO2 limit. This is done by assuming that each TRS compound has one sulfur atom (as is true for the most common TRS compounds – dimethyl sulfide, hydrogen sulfide, methyl mercaptan), in which case the number of SO2 atoms (or moles) would be the same as the number of TRS atoms (or moles) in the fuel gas. This calculation is performed on the basis of 1 standard cubic foot (ft3) of refinery fuel gas and associated heating value of the fuel gas, with the assumption that the gas is ideal(since flue gas molar volume is assumed to be 359 cf/lbmole) which is a valid assumption because of the relatively low pressure of the fuel gas.

SO2 (molecular weight 64.07):

(1 ft3/1,516 BTU)(lbmole/359 ft3)(45/MM)(64.07 lb/lbmole)
= **0.0053 lb/MM BTU**

Convert POC and PM10 "lb/MM ft3" to "lb/MM BTU":

This conversion may be done by applying the heating value of fuel gas.

POC: (5.5 lb/MM ft3)(1 ft3/1,516 BTU) = **0.0036 lb/MM BTU**

PM10: (7.6 lb/MM ft3)(1 ft3/1,516 BTU) = **0.0050 lb/MM BTU**

3.1.1.2 S-461 Emission Calculations

NOx: (439,800 MM BTU/yr)(0.013 lb/MM BTU)/(365 day/yr)
= **15.66 lb/day** = **2.86 ton/yr**

CO: (439,800 MM BTU/yr)(0.040 lb/MM BTU)/(365 day/yr)
= **48.20 lb/day** = **8.80 ton/yr**

SO2: (439,800 MM BTU/yr)(0.0053 lb/MM BTU)/(365 day/yr)
= **6.39 lb/day** = **1.17 ton/yr**

POC: (439,800 MM BTU/yr)(0.0036 lb/MM BTU)/(365 day/yr)
= **4.34 lb/day** = **0.79 ton/yr**

PM10: (439,800 MM BTU/yr)(0.0050 lb/MM BTU)/(365 day/yr)
= **6.02 lb/day** = **1.10 ton/yr**

3.1.2 Crude Unit Vacuum Tower Heater (S-36)

3.1.2.1 Assumptions and Emission Factors

The following assumptions will be used to estimate S-36 emissions:

- fuel: refinery fuel gas (natural gas backup)
- proposed utility: 100% (8,760 hr/yr)
- maximum firing rate: 82.1 MM BTU/hr
- nat. gas heat value: 1,050 BTU/scf (BAAQMD standard value)
- fuel gas heat value: 1,516 BTU/scf HHV (ConocoPhillips)
- annual fuel use: 719,200 MM BTU
- abatement device: selective catalytic reduction (SCR)
- ammonia slip from SCR: 10 ppm @ 3% O2

• emission factors (controlled):

POLLUTANT	EMISSION FACTOR	SOURCE
NOx	10 ppmvd @ 3% O2 [0.013 lb/MM BTU]	BAAQMD BACT Workbook, Determination 94.3.1 (8/12/94)
CO	28 ppmvd @ 3% O2 [0.023 lb/MM BTU]	BACT Determination, Section 6.1
POC	5.5 lb/MM ft3 [0.0036 lb/MM BTU]	U.S. EPA AP-42 Table 1.4-2 for natural gas
SO2	45 ppmv total reduced sulfur (TRS) in fuel gas [0.0053 lb/MM BTU]	BACT Determination, Section 6.1
PM10	7.6 lb/MM ft3 [0.0050 lb/MM BTU]	U.S. EPA AP-42 Table 1.4-2 for natural gas
NPOC	Negligible	U.S. EPA AP-42

Notes:

1. Ammonia emissions are quantified in Section 5.0 (Toxic Risk Management)
2. POC and PM10 emission factors are taken from AP-42 data for natural gas.

3.1.2.2 S-36 Emission Calculations

NOx: (719,200 MM BTU/yr)(0.013 lb/MM BTU)/(365 day/yr)
= **25.62 lb/day** = **4.67 ton/yr**

CO: (719,200 MM BTU/yr)(0.023 lb/MM BTU)/(365 day/yr)
= **45.32 lb/day** = **8.27 ton/yr**

SO2: (719,200 MM BTU/yr)(0.0053 lb/MM BTU)/(365 day/yr)
= **10.44 lb/day** = **1.91 ton/yr**

POC: (719,200 MM BTU/yr)(0.0036 lb/MM BTU)/(365 day/yr)
= **7.09 lb/day** = **1.29 ton/yr**

PM10: (719,200 MM BTU/yr)(0.0050 lb/MM BTU)/(365 day/yr)
= **9.85 lb/day** = **1.80 ton/yr**

3.1.3 Fugitive Components

ConocoPhillips has proposed to estimate fugitive emissions from new fugitive sources by using the "correlation equation" method from the 1999 document "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Refineries". This document, prepared by the California Air Resource Board and the California Air Pollution Control Officers Association, is the accepted District standard for estimating fugitive emissions. The correlation equation method is one of four methods described in this document, and is intended to be used to estimate emissions from an actual population of sources, using the measured emission concentrations from each source, and a corresponding emission factor. There are three possible types of emission factors: one corresponds to components with no measured leak, the second corresponds to non-pegged detected leaks, and the third corresponds to leaks that peg the analyzer high. Different sets of factors are provided for valves, pump seals, connectors, flanges, open-ended lines and "others" (a category which includes compressor seals). However, the service for each type of component (light liquid, heavy liquid or gas) is not considered.

In this case, the intent is to estimate the emissions from fugitive sources that are not yet in service. ConocoPhillips has proposed to implement the correlation equipment method by assuming that each fugitive component will have a leak with the maximum allowed concentration ("screening value") in ppm, as specified in District Regulation 8, Rule 18 ("Equipment Leaks"). Thus, the correlation equations that apply to non-pegged detected leaks will be used.

COMPONENT	CORRELATION EQUATION (KG/HR), PER COMPONENT	SCREENING VALUE (PPM)
VALVES	2.27E-6(screening value)^0.747	100
PUMP SEALS	5.07E-5(screening value)^0.622	500
OTHER (COMPRESSOR SEALS)	8.69E-6(screening value)^0.642	500
CONNECTORS	1.53E-6(screening value)^0.736	100
FLANGES	4.53E-6(screening value)^0.706	100

Notes:
1. Screening values are taken from District Regulation 8, Rule 18.
2. All emissions from fugitive components are assumed to be POC compounds.

All new fugitive components have been grouped into four locations:

LOCATION	VALVES	PUMP SEALS	COMPRESSOR SEALS	CONNECTORS	FLANGES
S-460 ULSD HYDROTREATER	2,009	11	7	735	490
S-304 NAPHTHA HYDROTREATER	2,009	11	7	735	490
S-462 FUEL GAS CAUSTIC TREATMENT	696	2	0	1,047	698
S-463 BUTANE CAUSTIC TREATMENT	696	2	0	1,047	698

Notes:

1. Fugitive component counts appear in Appendix B-1 of the application

3.1.3.1 Fugitive Components Emission Calculations

S-460 ULSD Hydrotreater:

[(2,009)(2.27E-6(100)^0.747) + (11)(5.07E-5(500)^0.622) +

(7)(8.69E-6(500)^0.642) + (735)(1.53E-6(100)^0.736) +

(490)(4.53E-6(100)^0.706] kg/hr (2.205 lb/kg) (24 hr/day)
= **13.91 lb/day POC**

S-304 Naphtha Hydrotreater:

[(2,009)(2.27E-6(100)^0.747) + (11)(5.07E-5(500)^0.622) +

(7)(8.69E-6(500)^0.642) + (735)(1.53E-6(100)^0.736) +

(490)(4.53E-6(100)^0.706] kg/hr (2.205 lb/kg) (24 hr/day)
= **13.91 lb/day POC**

S-462 Fuel Gas Caustic Treatment:

[(696)(2.27E-6(100)^0.747) + (2)(5.07E-5(500)^0.622) +

(1,047)(1.53E-6(100)^0.736) + (698)(4.53E-6(100)^0.706] kg/hr

(2.205 lb/kg) (24 hr/day) **= 9.70 lb/day POC**

S-463 Butane Caustic Treatment:

[(696)(2.27E-6(100)^0.747) + (2)(5.07E-5(500)^0.622) +

(1,047)(1.53E-6(100)^0.736) + (698)(4.53E-6(100)^0.706] kg/hr

(2.205 lb/kg) (24 hr/day) **= 9.70 lb/day POC**

Total Fugitive Component Emissions:

(13.91 + 13.91 + 9.70 + 9.70) lb/day = **47.22 lb/day POC**
= **8.62 ton/yr POC**

3.1.4 Cargo Carriers

As discussed in Section 2.14, there will be an increase in marine shipping of gas oil by barge and petroleum coke by freighter. Both barges and freighters require tugboats to guide them to and from the marine terminal. A single tugboat is required for barges; freighters require two tugboats. In addition to emissions from the use of main tugboat engines during maneuvering and cruising, emissions will also be produced by tugboat auxiliary engines while they are on standby, and by freighter auxiliary engines during hotelling.

Emissions from these marine operations are quantified in the project EIR (Appendix C, Section A.1.2) using emission factors and correlations from the EPA document "Analysis of Commercial Marine Vessel Emissions and Fuel Consumption Data" (February 2000). This is an acceptable method of quantifying these emissions. A copy of Appendix C of the EIR is attached.

Calculated total emission increases are as follows:

	GAS OIL EXPORT (4 trip/year) Ton/Year	PETROLEUM COKE EXPORT (1 trip/year) Ton/Year	TOTAL Ton/Year
PM	0.03	0.11	0.14
NOx	1.05	4.32	5.37
SO2	1.32	5.35	6.67
CO	0.12	0.39	0.51
POC	0.01	0.03	0.04

3.1.5 Paved Road Emissions

As described in the project EIR (Appendix C, Section A.1.1), 13 additional heavy-duty truck round trips per day will be necessary to import additional raw materials and to export additional products and waste. Based on the size of the refinery and the layout of access roads, ConocoPhillips has estimated a round-trip distance of 4 miles within the refinery.

Emissions are estimated with Equation 2 (with precipitation correction factor) from Chapter 13.2.1 ("Paved Roads") of U.S. EPA's AP-42:

$$E \text{ (lb/VMT)} = k\,(sL/2)^{0.65}(W/3)^{1.5}(1-P/4N)$$

E = emission rate
VMT = "vehicle miles traveled" = (4 mile/trip)(13 trip/day)
= 52 mile/day
k = particle size multiplier from Table 13.2.1-1
= 0.016 lb/VMT for PM10
sL = road surface silt loading from Table 13.2.1-2
= 0.4 g/m2 (default value for normal conditions on roads with less than 5,000 vehicles/day)
W = average weight (tons) of vehicles
= 30 tons based on the most common additional trip (coke transport), where a shipment is approximately 23 tons and a truck is assumed to weigh approximately 7 tons
P = number of "wet days" from Figure 13.2.1-2
= 60 days for the San Francisco Bay Area
N = number of days in the P averaging period
= 365 days

$$E\ (lb/VMT) = [(0.016)(0.4/2)^{0.65}(30/3)^{1.5}(1-60/4(365))]$$

$$= 0.17\ lb/mile$$

$$E\ (lb/day) = (0.17\ lb/mile)(52\ mile/day) = \mathbf{8.84\ lb/day}$$
$$= \mathbf{1.61\ ton/yr}$$

3.1.6 Coke Handling Emissions

U.S. EPA's AP-42 document includes a discussion of coking operations in Chapter 5.1 (Petroleum Refining). This chapter notes that delayed coking results in fugitive organic emissions (considered in Section 2.10), as well as particulate emissions from coke handling operations. However, it is also noted that particulate emission data is not available and no emission factors are provided for coke handling operations in Table 5.1.1 of this chapter. In the project EIR (Appendix C, Section A.8), the applicant estimated emissions from coke handling using the emission factors and procedures from U.S. EPA's AP-42, Chapter 13.2.4 ("Aggregate Handling and Storage Piles"). This is an acceptable method of quantifying these emissions. Assuming four un-covered transfer points for coke between the coker and the freighter used to ship the coke, and 186 ton/day of increased coke production, the total increase in PM10 emissions was calculated to be 0.02 ton/yr.

3.1.7 Total Annual Average Emissions

SOURCE	NOx (TON/YR)	CO (TON/YR)	SO2 (TON/YR)	POC (TON/YR)	PM10 (TON/YR)
HEATER S-461	2.86	8.80	1.17	0.79	1.10
HEATER S-36	4.67	8.27	1.91	1.29	1.80
FUGITIVE COMPONENTS				8.62	
PAVED ROAD TRAFFIC					1.61
MARINE CARRIERS	5.37	0.51	6.67	0.04	0.14
COKE HANDLING					0.02
TOTAL	12.90	17.58	9.75	10.74	4.67

3.2 Daily Emissions

Daily emissions are calculated to determine if best available control technology (BACT) requirements are triggered. In accordance with District Regulation 2-2-301, BACT is triggered for any new or modified source with the potential to emit 10 pounds of emissions or more of any class of regulated pollutant (NOx, CO, POC, SO2, PM10) on any day.

3.2.1 New ULSD Hydrotreater Charge Heater (S-461)

Because S-461 is proposed to operate at 100% utility, it will typical operate 24 hr/day and the daily emissions are equivalent to the calculated annual average emissions. BACT is triggered for NOx and CO.

3.2.2 Crude Unit Vacuum Tower Heater (S-36)

Because S-36 is proposed to operate at 100% utility, it will typical operate 24 hr/day and the daily emissions are equivalent to the calculated annual average emissions. BACT is triggered for NOx, CO and SO2.

3.2.3 Fugitive Components

Fugitive emissions are assumed to leak at the same rate, continuously. Therefore, the daily emissions are equivalent to the calculated annual average emissions. BACT is triggered for POC emissions from fugitive components at the S-460 and S-304 hydrotreaters.

3.2.4 Paved Road Traffic

Estimated road emissions from truck traffic are 8.84 lb/day on an annual average basis. However, since this emission rate reflects an adjustment for rain, and because some shipments do not occur every day, it appears that emissions are likely to exceed 10 lb/day on some days, for example on dry days when some less frequent shipments occur. Therefore, BACT will be assumed to be triggered. For unpaved road, BACT consists of water spray or chemical suppression of dust, as described in BACT determinations for rock and aggregate processing. No BACT determination has been made for paved roads, although obvious control measures would include sweeper trucks or watering trucks. Unfortunately, each of these measures would result in road emissions of their own, as well as additional engine emissions. Therefore, although dust control measures may be justified on unpaved road, they appear to be counter-productive on paved roads. Therefore, the use of paved roads will constitute BACT for truck road emissions.

3.2.5 Marine Cariers

Regulation 2-2-206 excludes cargo carriers from BACT requirements, therefore daily emissions from barge tugs and locomotives are irrelevant and will not be quantified.

3.2.6 Coke Handling

The calculated annual average emission increase represents 17% increase in coke production. Thus, total PM10 emissions from all coke handling operations are estimated to be:

(0.02 ton/yr)/(0.17) = 0.12 ton/yr

This is equivalent to less than 1 lb/day on an annual average basis. Since coke is produced every day, usually at the same rate, maximum daily emissions are not expected to be significantly higher than this annual average amount. Thus, total emissions from coke handling, even if considered as a single source, do not trigger BACT.

4.0 FACILITY CUMULATIVE INCREASE

Current cumulative increase values are taken from the District database (copies attached). Proposed increases are as calculated in Section 3.1 and summarized in Section 3.1.7.

POLLUTANT	CURRENT (TON/YR)	PROPOSED (TON/YR)	OFFSET AMOUNT (NOTE 2) (TON/YR)	NEW TOTAL (TON/YR)
POC	0.002	10.74	10.742	0.00
NOx	0.00 (note 1)	12.90	12.90	0.00
SO2	0.00	9.75	9.75	0.00
CO	142.620	17.58	0.00	160.20
PM10	9.67	4.67	0.00	14.34

Notes:

1. The database entry for NOx is actually -0.003. However, in accordance with the definition in Regulation 2-2-212, a cumulative increase is a positive number or zero. Therefore, a value of zero is used here.
2. Offsets are addressed in Section 7.0.

5.0 TOXIC RISK MANAGEMENT

In accordance with District Regulation 2-1-316, if “project emissions” of any compound that is identified in Table 2-1-316 of Regulation 2, Rule 1 exceeds the indicated “trigger level”, then a risk analysis is required. “Project emissions” include emissions from new sources and increased emissions from modified sources. The purpose of a risk analysis is to verify that the resulting toxic risk is not excessive. The District Toxic Risk Management Policy requires that emissions of all toxic air contaminants (TACs) associated with a project be included in the risk analysis if any single TAC exceeds its trigger level. Because trigger levels are expressed in units of “lb/yr”, the annual average emission rates from new and modified sources are the appropriate basis for project emissions. Also, emissions from “related projects” must also be considered. Related projects, according to the District Toxic Risk Management Policy, include all projects within the two-year period preceding an application, unless the emissions are demonstrated to be unrelated to those in the application. The following applications were processed in the two-year period (7/16/00-7/16/02) preceding the submittal of the application:

APPLICATION	PROJECT	RELATED PROJECT?
2076	Modify S-300 coker permit conditions to revise daily throughput limits.	Possibly, but this application resulted in no increase in annual toxic emissions.
2454	Retrofit combustion sources to comply with Regulation 9, Rule 10.	No. The modifications in this application were required by District regulations.
3449	Permit a new gasoline/naphtha storage tank, which replaced a smaller tank. Both tanks had floating roofs, although the older tank was riveted, while the new tank was welded.	Yes. Although the older tank had reached the end of its service life, it was replaced with a larger tank. Therefore, the increase in emissions from the new tank will be considered to be related to this project, since this project may result in an increase in gasoline production.
4984	Permit existing IC engines as required by a change in District regulations.	No. This application included no new or modified sources, and was required by District regulations,

As shown in this table, the only related project is the new tank in Application 3449. A risk analysis was performed in Application 3449 that estimated an increased excess cancer risk of 0.1 in a million. Therefore, an additional risk of 0.1 in a million will be added to any toxic risk for the sources in this application.

Total emissions from new and modified sources are identified and quantified in Section 3.1. Emissions of specific TACs are derived from overall emissions as shown in this table:

SOURCE	TAC CATEGORIES	SPECIFIC TAC EMISSION FACTORS
HEATERS S-461 AND S-36	Miscellaneous combustion products and non-combusted components of refinery fuel gas	WSPA/API report “Air Toxic Emission Factors for Combustion Sources Using Petroleum Based Fuels”, Final Report Volume 2, Appendix B, April 14, 1998
	ammonia slip from heater SCR systems	ammonia slip emission factor is calculated in Section 5.2 based on the proposed emission rate limit of 10 ppmv
FUGITIVE COMPONENTS	organic compounds in process streams where fugitive components are located	CARB’s California Emission Inventory Development and Reporting System, Organic Gas Speciation Profiles, 11/20/01 draft

5.1 S-461, S-36 Combustion Emissions

As noted in Section 5.0, the toxic emission factors for these heaters are taken from the referenced WSPA/API report. Specifically, emission factors are used for heaters using refinery gas fuel and abated with SCR. Four emission factors are provided based on the population of data in the specified source group: mean, median, maximum and minimum. ConocoPhillips has proposed to use the mean factor, which is acceptable. Eight compounds have emission factors in the report even though they were not detected in any source test conducted for the report (indicated with a "detect ratio" of 0.00 in the report). For these compounds, ConocoPhillips has proposed to use an emission factor of zero, rather than the factor from the report that is based on the detection limit of the analytical methods used, which is acceptable. Emissions in the report include ammonia slip emissions. Since these are calculated in Section 5.2 for the specific slip level that will be permitted, the ammonia factor in the report is not used.

The factors appear in Table A-12 of Appendix C of the project EIR and are as follows (excluding compounds with a detect ratio of zero and excluding ammonia):

COMPOUND	**EMISSION FACTOR (NOTE 2) (LB/MM BTU)**	**COMPOUND**	**EMISSION FACTOR (NOTE 2) (LB/MM BTU)**
acenaphthene	2.36E-09	formaldehyde	**1.11E-04**
acenaphthylene	1.55E-09	Indeno(1,2,3-cd)pyrene	**1.03E-07**
acetaldehyde	**1.53E-05**	lead	**4.89E-06**
antimony	5.17E-07	manganese	**6.81E-06**
arsenic	**8.50E-07**	mercury	**1.80E-07**
benzene	**6.47E-05**	naphthalene	**3.13E-07**
benzo(a)anthracene	**3.21E-08**	nickel	**9.42E-06**
benzo(a)pyrene	**8.96E-08**	phenanthrene	1.46E-08
benzo(b)fluoranthene	**4.04E-08**	phenol	**5.63E-06**
benzo(k)fluoranthene	**2.41E-08**	propylene	2.17E-06
cadmium	**9.88E-07**	pyrene	2.48E-09
chromium (note 1)	1.07E-06	selenium	**1.96E-08**
chrysene	1.63E-09	silver	1.61E-06
copper	**4.21E-06**	toluene	**1.07E-04**
ethylbenzene	3.02E-05	xylene (total)	**3.73E-05**
fluoranthene	3.06E-09	zinc	**2.08E-05**
fluorene	1.08E-08		

Notes:
1. No hexavalent chromium was detected, chromium (total) represents non-hexavalent chromium compounds.
2. Emission factors in bold are for compounds with assigned risk screening trigger levels in District Table 2-1-316.

Total annual fuel usage in Section 3.1 for heaters S-461 and S-36 is 1,159,000 MM/BTU. Therefore, the annual emissions of these compounds are:

COMPOUND	**ANNUAL EMISSIONS (LB/YR)**	**COMPOUND**	**ANNUAL EMISSIONS (LB/YR)**
acenaphthene	2.74E-03	formaldehyde	**1.29E+02**
acenaphthylene	1.80E-03	indeno(1,2,3-cd)pyrene	**1.16E-01**
acetaldehyde	1.77E+01	lead	5.67E+00

antimony	5.99E-01	manganese	7.89E-00
arsenic	**9.85E-01**	mercury	2.09E-01
benzene	**7.50E+01**	naphthalene	3.63E-01
benzo(a)anthracene	3.72E-02	nickel	**1.09E+01**
benzo(a)pyrene	**1.04E-01**	phenanthrene	1.69E-01
benzo(b)fluoranthene	**4.68E-02**	phenol	6.25E+00
benzo(k)fluoranthene	2.79E-02	propylene	2.52E+00
cadmium	**1.15E+00**	pyrene	2.87E-03
chromium (note 1)	1.24E+00	selenium	2.27E-02
chrysene	1.88E-03	silver	1.87E+00
Copper	4.88E+00	toluene	1.24E+02
ethylbenzene	3.50E+01	xylene (total)	4.32E+01
fluoranthene	3.55E-03	zinc	2.41E+01
fluorene	1.25E-02		

Notes:

1. Emission rates in bold are for compounds with emission rates that exceed the assigned risk screening trigger levels in District Table 2-1-316.

As shown in the table above, eight compounds have estimated emissions that exceed the assigned risk screening trigger levels. Therefore, a risk analysis is required for the toxic emissions in this application.

5.2 Ammonia Slip Emissions from A-461, A-36

Ammonia is present in the exhaust streams of the SCR systems (A-461, A-36) associated with the two new heaters, since the aqueous ammonia used in these devices is not completely reacted, resulting in some amount of ammonia “slip”. ConocoPhillips has proposed to limit slip to 10 ppmv @ 3% O2. Although ammonia may be present in trace concentrations in some fugitive emissions and in locomotive engine emissions, the exhaust streams from A-461 and A-36 are the predominant ammonia source related to this project, and no other ammonia sources are considered.

Convert ammonia "ppm" to "lb/MM scf":

This conversion may be done using the EPA "Fd" factor from 40 CFR Part 60 test methods, for example Method 19, Table 19-1-F. Fd is the ratio of the volume of dry flue gas to the heat value of the fuel used to produce the flue gas. Fd for natural gas is 8,710 dscf/MM BTU (from Method 19), Fd for refinery fuel gas is 8,700 dscf/MM BTU (from application Appendix B-2). Emission factors will be based on refinery fuel gas since this yields the higher emission factor. The conversion assumes that the flue gas is ideal (since flue gas molar volume is assumed to be 359 cf/lbmole) which is a valid assumption because of the relatively high temperature and low pressure of the flue gas. The conversion includes a correction of the pollutant concentrations from 3% O2 to 0% O2 (in accordance with District procedure ST-13A) since the flue gas volume assumes stoichiometric combustion (zero excess air and O2).

Ammonia Emission Factor (molecular weight 17.03):

(10/MM)(20.95%-0%/(20.95%-3%))(8,700 ft3/MM BTU)

(lbmole/359 ft3)(17.03 lb/lbmole) = **0.0048 lb/MM BTU**

Total annual fuel usage at S-461 and S-36:

(439,800 + 719,200) MM BTU/yr = **1,159,000 MM BTU/yr**

Annual Ammonia Emissions:

(0.0048 lb/MM BTU)(1,159,000 MM BTU/yr) = **5,563 lb/yr**

The trigger level for ammonia in Table 2-1-316 of Regulation 2, Rule 1 is 19,000 lb/yr. Therefore, a risk analysis is not triggered by project ammonia emissions. However, as shown in Section 5.1, a risk analysis is triggered by heater combustion emissions and will include these ammonia emissions.

5.3 Organic Compounds in Fugitive Emissions

As noted in Section 5.0, the toxic emission factors for fugitive components are taken from the California Air Resources Board document Organic Gas Speciation Profiles. Specifically, speciation profiles are taken from the spreadsheet ORGPROF_11_20_01.xls. This spreadsheet includes profiles for many classes of sources. ConocoPhillips has proposed to apply profiles 531, 316 and 760, depending on the type of service each component is in, as shown in Section 2.10. These profiles are described below, with the speciation data for all components with assigned risk screening trigger levels. Profile 531 is proposed, although it is for oil and gas extraction operations because no refinery-specific profile is provided. ConocoPhillips has proposed to apply either profile 316 or 760 to pump seals, even though profile 321 is a refinery-specific profile. Although profile 760 is appropriate for diesel cuts from the S-460 hydrotreater, profile 321 is more appropriate for pumps at the light naphtha streams at S-304 and the light liquid streams at the fuel gas and butane treatment units.

STREAM	PROFILE #	PROFILE DESCRIPTION	BENZENE (WT %)	N-HEXANE (WT %)	TOLUENE (WT %)	TOTAL XYLENE (WT %)
Gas	531	oil & gas extraction – compressor seals	0.7	1.4	0.4	0.0
Light liquid	316	Refinery pipes/valves/flanges – composite	0.1	3.4	0.5	0.2
Heavy liquid	760	evaporative emissions – distillate oil	0.0	9.0	0.0	0.0
Liquid	321	refinery pump seals - composite	0.5	11	3.0	1.3

Therefore, the following profiles shall be applied.

SOURCE	STREAM	PROFILE #	BENZENE (WT %)	N-HEXANE (WT %)	TOLUENE (WT %)	TOTAL XYLENE (WT %)
S-460 ULSD HYDROTREATER	Gas	531	0.7	1.4	0.4	0.0
	l liquid	321	0.5	11	3.0	1.3
	h liquid	760	0.0	9.0	0.0	0.0
S-304 NAPHTHA HYDROTREATER	Gas	531	0.7	1.4	0.4	0.0
	l liquid	321	0.5	11	3.0	1.3
	h liquid	321	0.5	11	3.0	1.3
S-462 FUEL GAS CAUSTIC TREATMENT	Gas	531	0.7	1.4	0.4	0.0
	l liquid	316	0.1	3.4	0.5	0.2
	h liquid	316	0.1	3.4	0.5	0.2
S-463 BUTANE CAUSTIC TREATMENT	Gas	531	0.7	1.4	0.4	0.0
	l liquid	316	0.1	3.4	0.5	0.2
	h liquid	316	0.1	3.4	0.5	0.2

Emissions of toxic compounds are calculated in the spreadsheet in Attachment 1. The results are:

SOURCE	STREAM	BENZENE (LB/YR)	N-HEXANE (LB/YR)	TOLUENE (LB/YR)	TOTAL XYLENE (LB/YR)
S-460 ULSD HYDROTREATER	Gas	9.74	19.48	5.56	0.00
	l liquid	4.79	105.32	28.72	12.45
	h liquid	0.00	245.48	0.00	0.00
S-304 NAPHTHA HYDROTREATER	Gas	9.74	19.48	5.56	0.00
	l liquid	4.79	105.32	28.72	12.45
	h liquid	13.64	300.03	81.83	35.46
S-462 FUEL GAS CAUSTIC TREATMENT	Gas	24.07	48.15	13.76	0.00
	l liquid	0.10	3.42	0.50	0.20
	h liquid	0.00	0.00	0.00	0.00
S-463 BUTANE CAUSTIC TREATMENT	Gas	24.07	48.15	13.76	0.00
	l liquid	0.10	3.42	0.50	0.20
	h liquid	0.00	0.00	0.00	0.00
TOTAL		**91.04**	**898.24**	**178.92**	**60.75**

Benzene emissions exceed the risk screening trigger level. As shown in Section 5.1, a risk analysis is already triggered by heater combustion emissions. These toxic emissions from fugitive components will be considered along with other project toxic emissions.

5.4 Toxic Risk Assessment

A risk analysis has been performed (see memo dated May 8, 2003) which estimated the following excess cancer risks and chronic hazard indexes:

RECEPTOR	RESIDENTIAL	NON-RESIDENTIAL
CANCER RISK	0.8 in a million	0.2 in a million
CANCER RISK (AN 3449)	0.1 in a million	0.03 in a million
TOTAL CANCER RISK	0.9 in a million	0.23 in a million
CHRONIC HAZARD INDEX	0.01	0.006
CHRONIC HAZARD INDEX (AN 3449)	0	0
TOTAL CHRONIC HAZARD INDEX	0.01	0.006

As the risk analysis concludes, this risk is acceptable because the limiting cancer risk (residential) is less than 1.0 in a million, and because the limiting chronic hazard index (residential) is less than 1.0, even after considering the additional risk from the related project in Application 3449.

6.0 NEW SOURCE REVIEW

6.1 Best Available Control Technology (BACT)

As determined in Section 3.2, BACT is triggered for NOx and CO at the S-461 heater, NOx, CO and SO2 at the S-36 heater, and POC at fugitive components.

6.1.1 NOx and CO at the S-461 heater

6.1.1.1 NOx

District BACT Guideline 94.3.1, last updated on August 12, 1994, specifies BACT 2 (achieved in practice) for a process heater with a heat input greater than 50 MM BTU/hr. BACT 2 is a maximum NOx emission concentration of 10 ppmvd @ 3% O2 (dry), averaged over any consecutive 3-hour period. This emission level will be met by the S-461 heater through the use of a combination of low NOx burners and the A-461 selective catalytic reduction (SCR) System using aqueous ammonia injection. No BACT 1 (technologically feasible) level is listed, which is consistent with listings from other agencies. The emission factors used in the Alternative Compliance Plan by the refineries to comply with Regulation 9, Rule 10 requirements are not below 10 ppmvd @ 3% O2. Therefore, BACT is a concentration not to exceed 10 ppmv at 3 percent O_2, dry.

6.1.1.2 CO

District BACT Guideline 94.3.1, last updated on August 12, 1994, specifies BACT 2 (achieved in practice) for CO, for a process heater with a heat input greater than 50 MM BTU/hr. BACT 2 is a CO concentration not to exceed 50 ppmvd @ 3% O2 (dry), averaged over any consecutive 3-hour period. No BACT 1 (technologically feasible) level is listed.

The Valero refinery (Plant 12626) has demonstrated in practice that a CO concentration limit of 28 ppmv at 3% O2 can be achieved in conjunction with a 10 ppmv NOx limit. This emission rate was achieved at the S-220 Hot Oil Furnace, permitted in Application 10392. A CO limit of 28 ppmv is also the proposed BACT level for new heaters in the application for refinery modernization currently under review (Application 5814).

ConocoPhillips has indicated that while a 28 ppmv CO limit is achievable at high firing rates at S-461, this heater will not operate at steady-state at full-load. ConocoPhillips has proposed a tiered CO standard, with firing rates of 50% or more subject to a 28 ppmv CO standard, and lower firing rates subject to a 50 ppmv CO standard, except during startup and shutdown periods not exceeding 24 hours. Because the 28 ppmv standard has been applied on a limited basis, this tiered standard will be adopted as BACT for S-461.

6.1.2 NOx, CO and SO2 at the S-36 heater

6.1.2.1 NOx

District BACT Guideline 94.3.1, last updated on August 12, 1994, specifies BACT 2 (achieved in practice) for a process heater with a heat input greater than 50 MM BTU/hr. BACT 2 is a maximum NOx emission concentration of 10 ppmvd @ 3% O2 (dry), averaged over any consecutive 3-hour period. This emission level will be met by the S-36 heater through the use of a combination of low NOx burners and the A-36 selective catalytic reduction (SCR) System using aqueous ammonia injection. No BACT 1 (technologically feasible) level is listed, which is consistent with listings from other agencies. The emission factors used in the Alternative Compliance Plan by the refineries to comply with Regulation 9, Rule 10 requirements are not below 10 ppmvd @ 3% O2. Therefore, BACT is a concentration not to exceed 10 ppmv at 3 percent O_2, dry.

6.1.2.2 CO

District BACT Guideline 94.3.1, last updated on August 12, 1994, specifies BACT 2 (achieved in practice) for CO, for a process heater with a heat input greater than 50 MM BTU/hr. BACT 2 is a CO concentration not to exceed 50 ppmvd @ 3% O2 (dry), averaged over any consecutive 3-hour period. No BACT 1 (technologically feasible) level is listed.

The Valero refinery (Plant 12626) has demonstrated in practice that a CO concentration limit of 28 ppmv at 3% O2 can be achieved in conjunction with a 10 ppmv NOx limit. This emission rate was achieved at the S-220 Hot Oil Furnace, permitted in Application 10392. A CO limit of 28 ppmv is also the proposed BACT level for new heaters in the application for refinery modernization currently under review (Application 5814). Therefore, BACT 2 (achieved in practice) for S-36 will be set at 28 ppmv at 3% O2.

6.1.2.3 SO2

District BACT Guideline 94.3.1, last updated on August 12, 1994, for a process heater with a heat input greater than 50 MM BTU/hour specifies:

- BACT 1 (technologically feasible and cost effective) is natural gas or treated refinery gas with the following sulfur limit:

  hydrogen sulfide (H2S) $\leq$ 50 ppmv
  total reduced sulfur (TRS) $\leq$ 100 ppmv

- BACT 2 (achieved in practice) is natural gas or treated refinery gas with a TRS level $\leq$ 100 ppmv.

The requirement to use only natural gas fuel as a BACT measure at ConocoPhillips is not applicable. Fuel gas is a waste material that would be flared if not combusted in the refinery furnaces and heaters. When fuel gas is available, it is preferable that it be treated and combusted rather than flared. S-36 is proposed to be operated normally on refinery fuel gas, with natural gas as a back-up fuel when insufficient refinery fuel gas is available.

ConocoPhillips uses a caustic scrubber system to treat recovered gases for use as refinery fuel gas. A similar system at the Valero refinery has consistently maintained TRS levels below 45 ppmv on a consecutive 365-day average basis. Therefore, BACT for SO2 for this project will be a TRS level not to exceed the "achieved in practice" level of 45 ppmv on a consecutive 365-day average basis. In addition, the 100 ppmv BACT 1 limit will be imposed as a daily average limit. A separate hydrogen sulfide (H2S) concentration limit is not needed since sulfur in H2S would be included in a TRS measurement. The District assumes that all of the sulfur compounds present in the refinery fuel gas, measured as TRS, is converted to SO2.

6.1.3 POC at fugitive components

As determined in Section 3.2, BACT is triggered for POC emissions from fugitive components at the S-460 and S-304 hydrotreaters. These sources include valves, flanges/connectors, and pump and compressor seals.

For S-460 and S-304, the emission contribution from each class of component is as follows:

COMPONENT	S-460 (LB/DAY)	S-304 (LB/DAY)
VALVES	7.53	7.53
PUMP SEALS	1.41	1.41
COMPRESSOR SEALS	0.17	0.17

CONNECTORS	1.76	1.76
FLANGES	3.03	3.03
TOTAL EMISSIONS	13.91	13.91

6.1.3.1 Valves

District BACT Guideline 136.1, last updated on June 30, 1995, specifies a BACT 2 (achieved in practice) emission standard of 100 ppm (as methane, measured at 1 cm from the component surface) for POC emissions from valves, and also requires that the valve be included in an approved inspection and maintenance program. No BACT 1 (technologically feasible) level is listed, nor is a stricter standard known to have been imposed elsewhere. Therefore, BACT 2 for valves will consist of a leak standard of 100 ppm, which corresponds to the standard in Regulation 8, Rule 18, plus inclusion in the Regulation 8, Rule 18 inspection and maintenance program.

6.1.3.2 Flanges / Connectors

District BACT Guideline 78.1, last updated on August 12, 1994, specifies a BACT 2 (achieved in practice) emission standard of 100 ppm (as methane, measured at 1 cm from the component surface) for POC emissions from flanges, and also requires that the flange be included in an approved inspection and maintenance program. No BACT 1 (technologically feasible) level is listed, nor is a stricter standard known to have been imposed elsewhere. Therefore, BACT 2 for flanges and connectors will consist of a leak standard of 100 ppm, which corresponds to the standard in Regulation 8, Rule 18, plus inclusion in the Regulation 8, Rule 18 inspection and maintenance program.

6.1.3.3 Pump Seals

District BACT Guideline 137.1, last updated on June 30, 1995, specifies the following:

- BACT 1 (technologically feasible and cost effective) is a leak standard of 100 ppm (as methane, measured at 1 cm from the component surface), and a quarterly inspection and maintenance program

• BACT 2 (achieved in practice) is a leak standard of 500 ppm (as methane, measured at 1 cm from the component surface), and a quarterly inspection and maintenance program

As shown in the table above, pumps seals contribute only 10% of the total fugitive emissions for both S-460 and S-304, based on a leak rate of 500 ppm. In fact, if pump seal emissions were eliminated entirely, both sources would continue to trigger BACT. Implementation of BACT 1 leak limits would require the use of non-standard seal technology and would complicate the inspection and monitoring program by imposing different standards on these pumps seals compared to all of the others at the refinery. Given the low emission contribution from pump seals, this is not considered justified. Therefore, BACT for pump seals will consist of the BACT 2 leak standard of 500 ppm, plus inclusion in the Regulation 8, Rule 18 inspection and maintenance program.

6.1.3.3 Compressor Seals

District BACT Guideline 48.B.1, last updated on June 30, 1995, specifies the following:

• BACT 1 (technologically feasible and cost effective) is a leak standard of 100 ppm (as methane, measured at 1 cm from the component surface), and a quarterly inspection and maintenance program

• BACT 2 (achieved in practice) is a leak standard of 500 ppm (as methane, measured at 1 cm from the component surface), and a quarterly inspection and maintenance program

As shown in the table above, compressor seals contribute only 1% of the total fugitive emissions for both S-460 and S-304, based on a leak rate of 500 ppm. Implementation of BACT 1 leak limits would require the use of non-standard seal technology and would complicate the inspection and monitoring program by imposing different standards on these compressor seals compared to all of the others at the refinery. Given the negligible emission contribution from compressor seals, this is not considered justified. Therefore, BACT for compressor seals will consist of the BACT 2 leak standard of 500 ppm, plus inclusion in the Regulation 8, Rule 18 inspection and maintenance program.

6.2 Emission Offsets

6.2.1 Offset Applicability

The most recent (2002) annual emissions inventory in the District’s database for ConocoPhillips is as follows:

NOx	1,647	ton/yr
VOC	766	ton/yr
PM10	87	ton/yr
SO2	760	ton/yr
CO	316	ton/yr

The emissions inventory was determined using actual throughput data from the refinery and source-specific emission factors. Based on this inventory, offsets are required for NOx and VOC emission increases (and pre-existing cumulative increase balances) in accordance with Regulation 2-2-302, since emissions of these pollutants exceed 15 ton/yr.

Also, offsets are required for SO2 emission increases (and pre-existing cumulative increase balances) in accordance with Regulation 2-2-303 since ConocoPhillips is a major facility for this pollutant, with facility emissions exceeding 100 ton/yr.

Although ConocoPhillips proposed to provide PM10 offsets, PM10 offsets are not required because modified facility emissions are not projected to exceed 100 ton/yr, after the proposed emission increases are considered. It should be noted that facility-wide PM10 emissions have never been estimated to exceed 100 ton/yr. Facility-wide PM10 emissions were estimated to be 87 ton/yr in 2002, the highest estimated total for this facility.

District regulations do not require offsets for CO emissions.

6.2.2 Required Offsets

ConocoPhillips has proposed to satisfy offset requirements by provided banking certificates for NOx, VOC and SO2 in the required quantities. Offsets are required at a ratio to the amount of offset emissions, as described in Regulations 2-2-302 (for POC and NOx) and 2-2-303 (for SO2).

POLLUTANT	OFFSET AMOUNT (NOTE 1) (TON/YR)	OFFSET RATIO	REQUIRED OFFSETS (TON/YR)
POC	10.742	1.15	12.35
NOx	12.90	1.15	14.84
SO2	9.75	1.0	9.75
CO	not required	not required	not required
PM10	not required	not required	not required

Notes:

1. The offset amount is the sum of the proposed emission increases, plus the pre-existing cumulative increase, as determined in Section 4.0.

ConocoPhillips has proposed to use the following banking certificates to provide the required offsets:

CERTIFICATE #	POC AVAILABLE	NOx AVAILABLE	SO2 AVAILABLE
131	0.38		
495	0.528		2.15
580	1.290	21.230	4.190
581	3.170	6.880	0.010
862			3.500
876	76.860		
total available	82.228	28.110	9.85
required offsets	12.350	14.840	9.75
balance	69.878 (Cert. 876)	6.39 (Cert. 580) 6.88 (Cert. 581)	0.10 (Cert. 862)

Notes:

1. Some of the indicated certificates also have available credits for CO and PM10, which are not required for this application. Those credits will remain on those certificates.

6.3 Prevention of Significant Deterioration (PSD)

PSD includes the requirements of Regulations 2-2-304, 2-2-305 and 2-2-306.

6.3.1 Regulation 2-2-304 (PSD Modeling)

Regulation 2-2-304.1 applies to new major facilities. The ConocoPhillips refinery is a major facility for NOx, POC, SO2 and CO emissions, with each class of pollutant exceeding 100 ton/yr. The refinery is not a major facility for PM10, and will not be a major facility for PM10 after the proposed modifications. Therefore, the refinery is not a **new** major facility for any class of pollutant.

Regulation 2-2-304.2 applies to major modifications (emission increases exceeding 40 ton/yr) of major facilities of SO2 and NOx. The proposed emission increases of SO2 and NOx are both less than 40 ton/yr and are not major modifications.

Therefore, no provision of this regulation is applicable.

6.3.2 Regulation 2-2-305 (CO Modeling)

The proposed emission increase of CO is less than 100 ton/yr and is not a major modification. Therefore, the CO modeling provision of this regulation is not applicable.

6.3.3 Regulation 2-2-306 (Non-Criteria Analysis)

The ConocoPhillips refinery is a major facility for more than one of the following pollutants: NOx, POC, SO2, CO, PM10. Therefore, the emission increase from this project may not exceed the following limits, since no PSD air quality analysis or visibility, soils and vegetations analysis has been performed:

POLLUTANT	ANNUAL AVERAGE LIMIT (TON/YR)	EMISSION EMISSION (TON/YR)	DAILY LIMIT (LB/DAY)	EMISSION EMISSION (LB/DAY)
lead	0.6	0.003	3.2	0.016
asbestos	0.007	0	0.04	0
beryllium	0.0004	0	0.002	0
mercury	0.1	0.0001	0.5	0.0006
fluorides	3	0.00005 (note 1)	16	0.00025 (note 1)
sulfuric acid mist	7	0	38	0
hydrogen sulfide	10	(note 2)	55	(note 2)
total reduced sulfur	10	(note 2)	55	(note 2)
reduced sulfur compounds	10	(note 2)	55	(note 2)

Notes:
1. Fluorides include fluorine-containing compounds emitted in traces at heaters S-461 and S-36.
2. Reduced sulfur compounds emitted from refinery sources are emitted to the atmosphere as SO2 when they are collected and used as fuel gas. There is not emission increase for untreated or unreacted reduced sulfur compounds.

As shown in this table, no PSD analysis is required for the specified non-criteria pollutants.

7.0 CEQA

The California Environmental Quality Act (CEQA) calls for a review of potential significant environmental impacts from proposed projects. This project has been determined to be subject to CEQA by the Contra Costa County Community Development Department (CCCCDD). The CCCCDD is the Lead Agency for CEQA for this project. In accordance with Regulation 2-1-310.3, the District may not issue an Authority to Construct for this project until final action has been taken by the Lead Agency. A draft Environmental Impact Report (EIR) was prepared by the CCCCDD in May 2003. This EIR includes all sources and activities that are the subject of this application. The District is a responsible agency under CEQA and has provided comments to the CCCCDD on the draft EIR. These comments, as well as others received by CCCCDD have been addressed in a revised EIR.

On December 2, 2003, the final EIR was certified by the Contra Costa County Planning Commission. On December 12, 2003, a mandatory 10-day appeal period for the EIR ended. Thus, the District may issue an Authority to Construct for this project.

8.0 REFINERY SO2 BUBBLE

The ConocoPhillips refinery operates under an “SO2 bubble” included in Condition 1694, Part 4. Since the new SO2 emissions in this application will be offset, the cap could be managed in two ways: 1) the cap amount could be increased by the amount of offset emissions, with emissions from the new sources included under the cap, or 2) the cap amount could be left unchanged, with emissions from new sources not required to be included under the cap. Since the first option will result in the simplest recordkeeping, this option will be implemented and the cap amount will be increased.

9.0 DISTRICT PROHIBITORY RULES

9.1 Regulation 6 (Particulate Matter and Visible Emissions)

Regulation 6 includes the Ringelmann 1 opacity limit in Regulation 6-301, the emission rate limit of 0.15 gr/dscf in 6-310, the nuisance fallout prohibition in 6-305 and the process rate limits in 6-311. New heaters will burn only gaseous fuels and are not likely to violate visible emission standards. Other new and modified sources, including fugitive components, also do not produce particulate emissions in quantities likely to result in result in violations. Sulfur is shipped in a molten state and is unlikely to result in a violation of this rule. Product coke is shipped offsite in a wet state and is also unlikely to result in a violation of this rule. This refinery has logged only 2 complaints in the last 10 years (both unconfirmed) for dust emissions. 90 visible emission complaints (34 confirmed) have been logged in the last 10 years. However, most of these complaints appear to be related to flaring events.

9.2 Regulation 8, Rule 5 (Storage of Organic Liquids)

No new tanks are proposed for this project. Some tanks, currently exempt from the requirements of Regulation 8, Rule 5 by virtue of the low vapor pressure of their contents, will see increased throughput of crude oil, gas oil and diesel oil. These tanks are expected to retain their exempt status. Existing gasoline tanks are also expected to see a nominal increase in throughput. No gasoline tank requires modification to accommodate this increase, and will continue to be subject to the design and operating requirements of Regulation 8, Rule 5. Un-modified tanks subject to Regulation 8, Rule 5 are assumed to be in compliance pending inspection.

9.3 Regulation 8, Rule 18 (Equipment Leaks)

Regulation 8, Rule 18 applies to equipment leaks at most refinery equipment, except for leaks at devices which are regulated by other rules (tank appurtenances, relief devices vented to control systems) and leaks at devices which handle low vapor pressure (initial boiling point greater than 302 degrees F). This regulation includes leak criteria, repair requirements for leaks and monitoring requirements. New fugitive devices associated with this project will largely be subject to this rule and will be incorporated into the maintenance and inspection program for fugitive devices and are assumed to be in compliance pending inspection.

9.4 Regulation 8, Rule 28 (Episodic Releases)

No new pressure relief devices are proposed for this project.

9.5 Regulation 9, Rule 1 (Sulfur Dioxide)

This regulation includes several requirements applicable to this project, as discussed below.

9.5.1 Regulation 9-1-301 (Ground Level SO2 Concentration)

Regulation 9-1-301 includes a limit on the ground level concentration of SO2. Because the facility sulfur-removal capacity will be increased to handle additional sulfur compounds in the crude oil feedstocks, ground level SO2 concentrations are not expected to increase.

9.5.2 Regulation 9-1-302 (SO2 Emission Limitations)

The 300 ppm SO2 emission limit in Regulation 9-1-302 applies to new heaters S-461 and S-36. These heaters will be limited (indirectly) to a lower SO2 emission rate by the proposed limit of 45 ppmv on TRS compounds in the feed gas. Because S02 and most of the reduced sulfur species contain a single sulfur molecule, the volumetric concentration of TRS in the feed gas should be roughly equivalent to the concentration in the exhaust gas, if the effect of combustion air is neglected. Thus, exhaust SO2 concentrations are expected to be less than 45 ppmv.

9.5.3 Regulation 9-1-303 (Emissions from Ships)

The 2,000 ppm SO_2 emission limit in Regulation 9-1-303 applies to ships that begin their journey outside the District. Thus, it may apply to some tugboats if they operate entirely within the District. Tugboats will be assumed to comply with this requirement rending an inspection.

9.5.4 Regulation 9-1-307 (Sulfur Recovery Plants)

The 250 ppm SO_2 emission limit in Regulation 9-1-307 does not apply to plants with SO_2 emissions less than 100 lb/day. The three sulfur plants at this refinery are estimated to have emissions below this level, based on emission inventory records, and therefore are assumed to not be subject to this limit.

9.5.5 Regulation 9-1-313.2 (Sulfur Recovery Operations at Petroleum Refineries)

This refinery is subject to the refinery-wide 95% H_2S recovery requirement for fuel gas and process water, and the refinery-wide 95% ammonia recovery requirement for process water. Compliance verification methods for this requirement are currently under consideration as part of the Title V permitting requirement for the refineries. The final permits are expected to contain a compliance monitoring provision. Compliance will be assumed pending implementation of this monitoring.

9.5.6 Regulation 9-1-501 (Area Monitoring)

Area monitoring is already required, at the request of the APCO, as described in this regulation.

9.6 Regulation 9, Rule 2 (Ground Level Hydrogen Sulfide Concentration)

Regulation 9, Rule 2 includes a limit on the ground level concentration of H_2S. Because the facility sulfur-removal capacity will be increased to handle additional sulfur compounds in the crude oil feedstocks, ground level H_2S concentrations are not expected to increase.

9.7 Regulation 9, Rule 10 (NOx and CO in Petroleum Refineries)

Regulation 9, Rule 10 (NO_x and CO from Boilers, Steam Generators, and Process Heaters in Petroleum Refineries) applies only to heaters that were permitted prior to January 5, 1994, in accordance with Regulation 9-10-220. Thus, new heaters S-461 and S-36 are not subject to this rule.

9.8 Regulation 10 (Standards of Performance for New Stationary Sources)

Regulation 10 adopts the federal New Source Performance Standards by reference. These are addressed in Section 10.1.

9.9 Regulation 11, Rule 7 (Benzene)

Regulation 11, Rule 7 applies only to equipment "in benzene service" which contains a gas or liquid which is at least 10% benzene by weight, in accordance with Regulation 11-7-207. There is no equipment in benzene service in this project.

9.10 Regulation 2-1-412 (Public Notification/K-12 Schools)

This facility is over 1,000 feet from the nearest school and therefore is not subject to the public notification requirements of Regulation 2-1-412.

10.0 FEDERAL REQUIREMENTS

Federal requirements include NSPS (40 CFR 60), NESHAP (40 CFR 61) and MACT (40 CFR 63) standards, which are discussed below.

10.1 New Source Performance Standards (NSPS)

NSPS standards apply to emissions from new or modified sources for which a specific standard has been written.

10.1.1 Subpart J (Petroleum Refineries)

Subpart J includes requirements for combustion devices and sulfur recovery plants in 40 CFR 60.104. Combustion devices, including the two new heaters (S-461 and S-36), are subject to a limit on H_2S concentration in the fuel gas (230 mg/dscm). The proposed BACT limits on TRS are stricter than this limit. The fuel gas system header will continue to be sampled to verify compliance. Sulfur plants are subject to a 250 ppmv SO_2 emission limit. The sulfur plants at this refinery are not subject to the NSPS because they were installed prior to the NSPS effective date. Because the two modified sulfur plants will not have increased emissions, they are not modified in the sense of the NSPS and continue to be exempt from its provisions. Nonetheless, it should be noted that the three sulfur plants comply with this limit.

10.1.2 Subpart GGG (Equipment Leaks of VOC in Petroleum Refineries)

Subpart GGG includes leak criteria, repair requirements for leaks and monitoring requirements. The refinery currently operates an inspection and maintenance program to comply with both Subpart GGG and District Regulation 8, Rule 18. New fugitive components will be included in this inspection and maintenance program and are assumed to be in compliance pending inspection.

10.2 National Emission Standards for Hazardous Air Pollutants (NESHAPS)

NESHAPS apply to eight specific pollutants, including benzene. A review of these standards shows that most are obviously not applicable, and only two standards require detailed discussion.

10.2.1 Subpart BB (Benzene transfer Operations)

Subpart BB applies to loading racks for benzene. No loading racks are proposed as part of this project. Further, the regulation specifically excludes transfer of the types of liquids that are associated with this project (40 CFR 61.300), including gasoline, crude oil and petroleum distillates.

10.2.2 Subpart FF (Benzene Waste)

Subpart FF applies to petroleum refineries and includes waste-handling requirements for several categories of sources. Because this refinery handles less than 10 megagram/yr of benzene waste (40 CFR 61.300), none of these operating requirements are applicable, and the refinery is subject only to recordkeeping provisions. The proposed new sources and modifications will not change this status.

10.3 Maximum Achievable Control Technology (MACT)

MACT standards apply to toxic emissions from specific operations, as described below.

10.3.1 Subpart CC

Subpart CC (Petroleum Refineries) applies to various refinery operations, including: miscellaneous process vents, wastewater streams, equipment leaks, and marine vessel loading operations. Compliance with these requirements is addressed in detail in the proposed Title V permit for this facility. Miscellaneous process vents are required to either be controlled, or else limited to 15 lb/day of VOC emissions. Since Regulation 8, Rule 2 limits vents to 15 lb/day, compliance with this standard is assured. No controls are proposed in this MACT for wastewater streams at facilities like this refinery with less than 10 megagram/yr of benzene loading. For equipment leaks, compliance with the standards of this MACT is assured by compliance with the more strict requirements of District Regulation 8, Rule 18.

10.3.2 Subpart UUU

Subpart UUU applies to catalytic cracking units, catalytic reforming units and sulfur plants. The only affected sources in this application are the sulfur plants. This standard requires that all vents from sulfur plants not exceed a TRS emission equivalent to 300 ppmv SO_2 (0% oxygen). The compliance date for this requirement is April 11, 2005.

11.0 PERMIT CONDITIONS

11.1 Sources with Modified Conditions

11.1.1 Crude Unit S-300

Crude Unit S-300 is currently subject to Condition 476. In addition to the throughput increase in Part B.1, some editorial changes are proposed, including:

- deletion of Part A: the terms defined in this section were previously deleted from this condition
- deletion of Part D since the annualized limit referred to is deleted
- deletion of unnecessary headings, renumbering and addition of standard text regarding the owner/operator

CONDITION 476

APPLICATION 5814; CONOCOPHILLIPS SF REFINERY; PLANT 16
CONDITIONS FOR S-300

1. The owner/operator of S-300 shall not exceed a total charging rate to S-300 (Coking Unit 200) of 81,000 barrels on any day.

[Cumulative Increase]

2. The owner/operator shall maintain a file which contains (1) all measurements, records, charts and other data which must be collected pursuant to the provisions of this conditional permit and (2) such other data and calculations necessary to determine actual emissions from emission points covered by this permit. This file (which may contain confidential or proprietary data) shall include, but not be limited to: records of quantities of crude oil and other hydrocarbons processed on an actual daily basis. This material shall be kept available for District inspection for a period of at least 5 years following the date on which such measurements, records or other data are made or recorded.
[BACT,
Cumulative Increase]

3. Each month, within 30 days of the end of the month an operational report shall be made to the APCO. Each monthly report shall include the following information for the month being reported:

a. S-300 daily charging rate for all feed streams
[BACT,
Cumulative Increase]

11.1.2 Crude Unit S-350

As discussed in Section 2.3, only editorial changes are proposed to Condition 383:

CONDITION 383

APPLICATION 5814; CONOCOPHILLIPS SF REFINERY; PLANT 16
CONDITIONS FOR S-350

1a. The owner/operator of S-350 (Crude Unit 267) shall not process crude oil at S-350 with a sulfur content in excess of 1.5 wt %.

[Cumulative Increase]

1b. The owner/operator shall sample and analyze the crude feed to S-350 to determine the sulfur content each time a new tanker shipment or pipeline delivery of crude is introduced into the S-350 feed tanks.
[Cumulative Increase]

2. The owner/operator of S-350 shall not exceed an S-350 feed rate of 30,000 bbl per day on a 12 month rolling average basis. The S-350 feed rate shall never exceed 33,000 bbl on any calendar day. The 33,000 bbl/day limit and 30,000 bbl/day 12 month rolling average limit are absolute limits and may not be corrected for instrument error.
[Cumulative Increase]

3. The owner/operator of S-350 shall maintain monthly records of "calendar day" throughput and "12 month rolling average" throughput at S-350 in a District-approved log. The owner/operator shall also maintain records of all sulfur content analyses required by Part 1b. These records shall be kept for at least five years and shall be made available to the District upon request.
[Cumulative Increase]

11.1.3 SO2 Bubble

As discussed in Section 8.0, the SO2 Bubble in Condition 1694, Part 4 will be revised to include new SO2 emissions that are offset. Because this condition is lengthy only the section related to the bubble is shown. Since the only liquid fuel burned at the facility is naphtha (see Major Facility Permit), references to fuel oil and diesel fuel will be replaced by a reference to liquid fuel. The offset amount of SO2 emissions is:

9.75 ton/yr = 53 lb/day

And the new cap amount is:

(1,558 lb/day) + (53 lb/day) = 1,611 lb/day

APPLICATION 5814; CONOCOPHILLIPS SF REFINERY; PLANT 16
CONDITIONS FOR COMBUSTIONS SOURCES, INCLUDING NON-COGEN SO2 CAP

4. Emissions of SO2 shall not exceed 1,611 lb/day on a monthly average basis from non-cogeneration sources burning fuel gas or liquid fuel. [SO2 Bubble]

11.2 New/Modified Sources

11.2.1 S-460 ULSD Hydrotreater

APPLICATION 5814; CONOCOPHILLIPS SF REFINERY; PLANT 16
CONDITIONS FOR S-460 HYDROTREATER

1. The owner/operator of S-460 shall not exceed a feed rate of 35,000 bbl/day on a monthly average basis at this unit. [Regulation 2-1-234]

2. The owner/operator of S-460 shall maintain the following records in a District-approved log. These records shall be kept for at least 5 years and shall be made available to the District upon request.

a. Daily records of feed throughput
b. Average daily feed rate for each calendar month [Regulation 2-1-234]

11.2.2 S-461 Hydrotreater Charge Heater

APPLICATION 5814, CONOCOPHILLIPS REFINERY; PLANT 16
CONDITIONS FOR S-461 HEATER

1. The owner/operator of the S-461 heater shall fire only refinery fuel gas or natural gas at this unit. [BACT, Cumulative Increase]

2. Based on refinery gas HHV, the owner/operator of S-461 shall not exceed the following firing rates:

a. 50.2 million BTU/hr
b. 439,800 million BTU in any consecutive 12-month period.

[Cumulative Increase]

3a. The owner/operator of S-461 shall abate emissions from S-461 at the A-461 SCR system whenever S-461 is operated.
[BACT, Cumulative Increase]

3b. The owner/operator of A-461 shall not exceed the following emission rates from S-461/A-461 except during startups and shutdowns. Startups and shutdowns shall not exceed 24 consecutive hours. The 24-consecutive-hour startup period is in addition to heater dryout/warmup periods, which shall not exceed 72 consecutive hours.

NOx 10 ppmv @ 3% oxygen (3 hr average) [BACT, Cumulative Increase]
CO 28 ppmv @ 3% oxygen (8 hr average) at 25.1 MM BTU/hr and higher
firing rates, 50 ppmv @ 3% oxygen (8 hr average) at firing rates
below 25.1 MM BTU/hr [BACT, Cumulative Increase]
POC 5.5 lb/MM ft3 [Cumulative Increase]
PM10 7.6 lb/MM ft3 [Cumulative Increase]
ammonia 10 ppmv @ 3% oxygen (8 hr average) [Toxic Management]

Note: Part 3b shall not apply until after the conclusion of the initial startup of S-461.

4. The owner/operator shall equip S-461 with a District-approved continuous fuel flow monitor and recorder in order to determine fuel consumption. A parametric monitor as defined in Regulation 1-238 is not acceptable. The owner/operator shall keep continuous fuel flow records for at least five years and shall make these records available to the District upon request.

[Cumulative Increase]

5a. The owner/operator shall install, calibrate, maintain, and operate a District-approved continuous emission monitor and recorder for NOx and O2. The owner/operator shall keep NOx and O2 data for at least five years and shall make these records available to the District upon request.
[BACT, Cumulative Increase]

5b. Following the initial source test required in Part 8, the owner/operator shall monitor compliance with the CO emission rate limit in Part 3b with a District-approved semi-annual source test, with at least one source test per year deemed by the District to be representative of normal operation. The owner/operator shall

submit the source test results to the District staff no later than 60 days after the source test. The time interval between source tests shall not exceed 8 months. CO source tests performed by the District may be substituted for semi-annual CO source tests. If two or more CO source tests, over any consecutive five year period, indicate a CO emission rate of 200 ppmv @ 3% O2 or higher, the owner/operator shall install and operate a District-approved continuous CO monitor/recorder within the time period specified in the District Manual of Procedures.
[BACT, Cumulative Increase]

6. The owner/operator shall use only refinery fuel gas at S-461 which does not exceed the following limits:

a. 100 ppmv totaled reduced sulfur (TRS), averaged over a calendar day
b. 45 ppmv TRS, averaged over any rolling consecutive 365-day period.
[BACT, Cumulative Increase]

7a. The owner/operator shall test refinery fuel gas prior to combustion at S-461 to determine total reduced sulfur (TRS) concentration by GC analysis at least once per 8 hour shift (3 times per calendar day). At least 90% of these samples shall be taken each calendar month. No readable samples or sample results shall be omitted. TRS shall include hydrogen sulfide, methyl mercaptan, methyl sulfide, dimethyl disulfide. If the TRS value, averaged over any rolling consecutive 365-day period, exceeds 35 ppmv, the owner/operator shall install and operate a District-approved continuous monitor/recorder to determine the total reduced sulfur content of the refinery fuel gas prior to combustion in S-461 within the time period specified in the District Manual of Procedures. [BACT, Cumulative Increase]

7b. To demonstrate compliance with Part 6, the owner/operator shall measure and record the 24-hour average TRS content and the 365-day average TRS content of the refinery fuel gas fired in S-461, unless required to operate a District-approved continuous monitor/recorder by Part 7a. The owner/operator shall keep TRS records, whether they are the results of GC analysis or continuous analyzer data, for at least five years and shall make these records available to the District upon request. [BACT, Cumulative Increase]

8. No later than 90 days from the startup of the S-461, the owner/operator shall conduct District-approved source tests to determine initial compliance with the limits in Part 3b for NOx, CO, POC, PM10 and ammonia. The owner/operator shall conduct the source tests in accordance with Part 9. The owner/operator shall

submit the source test results to the District staff no later than 60 days after the source test.
[BACT, Cumulative Increase, Toxic Management]

9. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emissions monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section, in writing, of the source test protocols and projected test dates at least 7 days prior to testing.
[BACT, Cumulative Increase, Toxic Management]

11.2.3 S-304 Hydrotreater

APPLICATION 5814; CONOCOPHILLIPS REFINERY; PLANT 16
CONDITIONS FOR S-304 HYDROTREATER

1. The owner/operator of S-304 shall not exceed a feed rate of 12,198 bbl/day on a monthly average basis. [Regulation 2-1-234]

2. The owner/operator of S-304 shall maintain the following records in a District-approved log. These records shall be kept for at least 5 years and shall be made available to the District upon request.

a. Daily records of feed throughput
b. Average daily feed rate for each calendar month

[Regulation 2-1-234]

11.2.4 S-36 Crude Unit Vacuum Tower Heater

APPLICATION 5814, CONOCOPHILLIPS REFINERY; PLANT 16
CONDITIONS FOR S-36 HEATER

1. The owner/operator of the S-36 heater shall fire only refinery fuel gas or natural gas at this unit.
[BACT, Cumulative Increase]

2. Based on refinery gas HHV, the owner/operator of S-36 shall not exceed the following firing rates:

a. 82.1 million BTU/hr
b. 719,200 million BTU in any consecutive 12-month period.
[Cumulative Increase]

3a. The owner/operator of S-36 shall abate emissions from S-36 at the A-36 SCR system whenever S-36 is operated. [BACT, Cumulative Increase]

3b. The owner/operator of S-36 shall not exceed the following emission rates from S-36/A-36 except during startups and shutdowns. Startups and shutdowns shall not exceed 24 consecutive hours. The 24-consecutive-hour startup period is in addition to heater dryout/warmup periods, which shall not exceed 72 consecutive hours.

NOx	10 ppmv @ 3% oxygen (3 hr average)	[BACT, Cumulative Increase]
CO	28 ppmv @ 3% oxygen (8 hr average)	[BACT, Cumulative Increase]
POC	5.5 lb/MM ft3	[Cumulative Increase]
PM10	7.6 lb/MM ft3	[Cumulative Increase]
ammonia	10 ppmv @ 3% oxygen (8 hr average)	[Toxic Management]

Note: Part 3b shall not apply until after the conclusion of the initial startup of S-36.

4. The owner/operator shall equip S-36 with a District-approved continuous fuel flow monitor and recorder in order to determine fuel consumption. A parametric monitor as defined in Regulation 1-238 is not acceptable. The owner/operator shall keep continuous fuel flow records for at least five years and shall make these records available to the District upon request.

[Cumulative Increase]

5a. The owner/operator shall install, calibrate, maintain, and operate a District-approved continuous emission monitor and recorder for NOx and O2. The owner/operator shall keep NOx and O2 data for at least five years and shall make these records available to the District upon request.
[BACT,
Cumulative Increase]

5b. Following the initial source test required in Part 8, the owner/operator shall monitor compliance with the CO emission rate limit in Part 3b with a District-approved semi-annual source test, with at least one source test per year deemed by the District to be representative of normal operation. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test. The time interval between source tests shall not exceed 8 months. CO source tests performed by the District may be substituted for semi-annual CO source tests. If two or more CO source tests, over any consecutive five year period, indicate a CO emission rate of 200 ppmv @ 3% O2 or higher, the owner/operator shall install and operate a District-approved

continuous CO monitor/recorder within the time period specified in the District Manual of Procedures.
[BACT, Cumulative Increase]

6. The owner/operator shall use only refinery fuel gas at S-36 which does not exceed the following limits:

a. 100 ppmv totaled reduced sulfur (TRS), averaged over a calendar day
b. 45 ppmv TRS, averaged over any rolling consecutive 365-day period.
[BACT, Cumulative Increase]

7a. The owner/operator shall test refinery fuel gas prior to combustion at S-36 to determine total reduced sulfur (TRS) concentration by GC analysis at least once per 8 hour shift (3 times per calendar day). At least 90% of these samples shall be taken each calendar month. No readable samples or sample results shall be omitted. TRS shall include hydrogen sulfide, methyl mercaptan, methyl sulfide, dimethyl disulfide. If the TRS value, averaged over any rolling consecutive 365-day period, exceeds 35 ppmv, the owner/operator shall install and operate a District-approved continuous monitor/recorder to determine the total reduced sulfur content of the refinery fuel gas prior to combustion in S-36 within the time period specified in the District Manual of Procedures. [BACT, Cumulative Increase]

7b. To demonstrate compliance with Part 6, the owner/operator shall measure and record the 24-hour average TRS content and the 365-day average TRS content of the refinery fuel gas fired in S-36, unless required to operate a District-approved continuous monitor/recorder by Part 7a. The owner/operator shall keep TRS records, whether they are the results of GC analysis or continuous analyzer data, for at least five years and shall make these records available to the District upon request. [BACT, Cumulative Increase]

8. No later than 90 days from the startup of the S-36, the owner/operator shall conduct District-approved source tests to determine initial compliance with the limits in Part 3b for NOx, CO, POC, PM10 and ammonia. The owner/operator shall conduct the source tests in accordance with Part 9. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test.
[BACT, Cumulative Increase, Toxic Management]

9. The owner/operator shall obtain approval for all source test procedures from the District’s Source Test Section prior to

conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emissions monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section, in writing, of the source test protocols and projected test dates at least 7 days prior to testing.
[BACT, Cumulative Increase, Toxic Management]

11.2.5 Fugitive Components

APPLICATION 5814; CONOCOPHILLIPS REFINERY; PLANT 16
CONDITIONS FOR ULSD PROJECT FUGITIVE COMPONENTS

1. The owner/operator shall equip all light hydrocarbon control valves installed as part of the USLD Project with live loaded packing systems and polished stems, or equivalent.
[BACT]

2. The owner/operator shall equip all flanges/connectors installed in the light hydrocarbon piping systems as part of the USLD Project with graphitic-based gaskets unless the service requirements prevent this material. [BACT]

3. The owner/operator shall equip all new hydrocarbon centrifugal compressors installed as part of the USLD Project with "wet" dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas.
[BACT]

4. The owner/operator shall equip all new light hydrocarbon centrifugal pumps installed as part of the USLD Project with a seal-less design or with dual mechanical seals with a heavy liquid barrier fluid, or equivalent. [BACT]

5. The owner/operator shall integrate all new fugitive equipment installed as part of the USLD Project, in organic service, into the facility fugitive equipment monitoring and repair program.
[BACT]

6. The Owner/Operator shall submit a count of installed pumps, compressors, valves, and flanges/connectors every 180 days until completion of the project. For flanges/connectors, the owner/operator shall also provide a count of the number of graphitic-based and non-graphitic gaskets used. The owner/operator has been permitted to install fugitive components (5,410 valves, 2,376 flanges, 3,564 connectors, 26 pumps, 14 compressors) with a total POC emission rate of 8.62 ton/yr. If there is an increase in the total fugitive component emissions, the plant's cumulative emissions for the project shall be adjusted to reflect the difference between emissions based on predicted versus actual

component counts. The owner/operator shall provide to the District all additional required offsets at an offset ratio of 1.15:1 no later than 14 days after the submittal of the final POC fugitive equipment count. If the actual component count is less than the predicted, at the completion of the project, the total will be adjusted accordingly and all emission offsets applied by the owner/operator in excess of the actual total fugitive emissions will be credited back to owner/operator prior to issuance of the permits.

[BACT, Cumulative Increase, Toxic Management]

12.0 RECOMMENDATION

Grant Authority to Construct to ConocoPhillips for the following:

Issue an Authority to Construct to ConocoPhillips Petroleum for:

S-460 ULSD Hydrotreater (Unit 250): 35,000 bbl/day of diesel stock

S-461 ULSD Hydrotreater Charge Heater: 50.2 MM BTU/hr (HHV); refinery gas-fired; abated by A-461 SCR system

A-461 SCR: aqueous ammonia, to abate S-461 heater

S-462 Fuel Gas Caustic Treatment System (Unit 215): caustic scrubber, a caustic solution stripper, storage tanks for caustic solution and amine solution (MEA) used for caustic recycling; 4.2 million standard cubic feet per day of fuel gas from Unit 233

S-463 Butane Caustic Treatment System (Unit 215): caustic scrubber, a caustic solution stripper, storage tanks for caustic solution and amine solution (MEA) used for caustic recycling; 1,000 bbl/day of butane stock from Unit 215

S-304 Light Naphtha Hydrotreater (Unit 229): Service change from diesel hydrotreating with reactor and heat exchanger modifications; naphtha processing capacity of 12,198 bbl/day.

S-350 Crude Unit (Unit 267): Change bottoms flow from S-300 coker to S-300 vacuum tower; internal modification to towers

S-300 Crude/Coker Unit (Unit 200): Replace vacuum and atmospheric towers; total processing capacity of 81,000 bbl/day

S-36 Crude Unit Vacuum Tower Feed Heater: 82.1 MM BTU/hr (HHV); refinery gas-fired; abated by A-36 SCR system

A-36 SCR: aqueous ammonia, to abate S-36 heater

S-1002 Sulfur Recovery Plant: Modify to use pure oxygen; 86 LTD nominal sulfur removal capacity; 271 long ton/day total sulfur plant capacity at S-1001, S-1002 and S-1003

S-1003 Sulfur Recovery Plant: Modify to use pure oxygen; 115 LTD nominal sulfur removal capacity; 271 long ton/day total sulfur plant capacity at S-1001, S-1002 and S-1003

Miscellaneous Modifications:
- **Replace amine stripper heat exchangers**
- **Install new 230 gpm sour water stripper**

Issue a permit exemption to ConocoPhillips Petroleum for:

S-500 ULSD Cooling Tower: 11 MM gal/day; exempt in accordance with Regulation 2-1-128.4

original signed by:

By: ____

J. Julian Elliot
Senior Air Quality Engineer

JE:je
5814.doc

APPENDIX G

Schedule of Compliance – S-425, S-426

APPENDIX H

Response to Comments from ConocoPhillips (12/24/03 e-mail, 4/3/04 letter)

Responses to Comments from ConocoPhillips (12/24/03 e-mail and 4/3/04 letter)

A. E-mail dated 12/24/03 from Valerie Uyeda

[In body of e-mail] S-319 was originally an independent process unit. When the S-350 crude unit was put into service, S-319 became the light ends fractionation section for S-350. All feed to S-319 comes from S-350. S-319 has no dedicated process heaters. S-319 has a separate control room from S-350. ConocoPhillips has processed to delete S-319 as a source, and to include S-319 fugitive components as part of S-350.

Response: To the extent that current permit conditions at S-319 bottleneck S-350 production, they are essentially permit conditions for S-350. Because it has not been established that S-319 conditions do not bottleneck S-350, it is not appropriate to deleted S-319 as a source, along with its permit conditions. A permit application will be required to establish the relationship between S-319 and S-350 and possibly to incorporate S-319 into S-350.

The following comments are taken from Attachment 1A to the e-mail:

1. Condition 18255, Part 3 should apply to flare S-398, but not S-296 because S-296 is not subject to NSPS Subpart J.

Response: Tables IV and VII-L and Condition 18255 indicate that 60.104 applies only to S-398.

2. Use alternate language for flare condition 18255

Response: The flare condition language has been revised.

3. Increase S-319 daily throughput limit to correspond to 4.32 E 6 bbl/yr (or 11836 bbl/day).

Response: S-319 daily throughput was corrected to 9,600 bbl/day in response to permit appeal and annual throughput was adjusted to correspond to this amount.

4. Delete standards for floating roofs for API separators in Table IV-C since separator has a fixed roof.

Response: Standards are deleted.

5. Delete monitoring for floating roofs for API separators in Table VII-C since separator has a fixed roof.

Response: Monitoring is deleted.

6 and 7. Deleted permit shield in Table IX B-1 (shield is transferred to Table IX A-1 where it should be since this is not a shield for a subsumed requirement.

Response: Permit shield is transferred to Table IX A-1.

8. Disagree with basis (any 12-month consecutive period) for throughput limits in Condition 20989.

Response: This condition previously was deficient in that it did not specify a time basis. The basis of any consecutive 12-month period is the standard basis imposed by the District for throughput limits.

9. Correct basis date of April 11, 2004 in Condition 20620.

Response: This date has been deleted.

10. Delete citations for NESHAP Subpart FF 61.350, 61.356(k), and 61.357(d)(8) in Table IV-All Sources since these requirements do not apply to this facility.

Response: Citations to NESHAP Subpart FF 61.350, 61.356(k), and 61.357(d)(8) are deleted. A monitoring reference to Subpart FF 61.342(a)(2) is not included in this table.

11, 12, 13, 15, 16. Change Tables IV A-13, A-14, A-15, A-16 and A-17 to refer to a group firing limit for S-15, S-16, S-17, S-18 and S-19.

Response: Tables IV A-13, A-14, A-15, A-16 and A-17 have been revised.

14. Change federal enforceability of Condition 1694, Part 1 in Table VII-A.16 from Y to N to correspond to Table IV-A.16 and Condition 1694.

Response: This change has been made.

17. Deleted heading reference to S-53 through S-58 above Parts 1 and 2 of Condition 19488 since these parts apply only to S-50, S-51 and S-52.

Response: References to S-53 through S-58 have been deleted.

18, 22, 23. Change description of tanks S-126, S-257 and S-258 in Table II-A from external floating roof to internal floating roof tank with dome roof to indicate that these tanks now operate as internal floating roof tanks because they have been retro-fitted with dome roofs.

Response: These descriptions have been changed.

19, 20, 21, 30, 33, 34, 35, 36, 37, 38, 39. Change monitoring frequency (for tank seal replacement records) from "periodic after each tank seal inspection" to "periodic after each tank seal replacment"

Response: This frequency has been changed.

24. Change second citation of Condition 7523 in Table IV-K to Condition 18680.

Response: This correction has been made.

25. Add heading to Condition 18680 to indicate that it applies to S-294.

Response: Condition 18680 is a "generic" condition that is applied to several gasoline dispensing facilities. Specific sources cannot be cited in this condition.

26. Add heading to Condition 476 to clarify that it applies to S-300.

Response: Condition 476 has been replaced by Condition 21092.

27. Table IV-U should refer to a requirement in Condition 20620 for a "Operation, Maintenance, and Monitoring Plan" instead of a "Startup, Shutdown, and Malfunction Plan".

Response: This correction has been made.

28. Change S-305 annual throughput from 9.21 E 6 to 9.23 bbl/yr to correspond to daily capacity in Table II-A.

Response: This correction has been made.

29. Table IV-N should refer to a requirement in Condition 20620 for a "Operation, Maintenance, and Monitoring Plan" instead of a "Startup, Shutdown, and Malfunction Plan".

Response: This correction has been made.

31, 32. Delete "daily" frequency in sampling requirement cited in Table IV-O for Condition 383, Pat 1b, since frequency is on an event basis. Also, correct frequency in Table VII-O.

Response: "Daily" frequency has been changed to a periodic/event frequency.

B. Letter dated 4/13/04 from Phillip Stern

[In body of letter]. Transfer permit shield for API separator from Table IX B-1 (which is deleted) to Table IX A-1. Since this is not a subsumed requirement, it should be included in Table IX A-1.

Response: This change was made in response to e-mail dated 12/24/03.

[In body of letter]. Oxidizer A-420 is subject to NSPS Subpart J. A schedule of compliance should be added to the permit.

Response: A-420 has been identified as subject to this requirement. The schedule of compliance will be attached to the SOB.

[In body of letter]. Change Responsible Official to J Michael Kenney, Refinery Manager.

Response: This name change was previously made. The title of the Responsible Official has been changed from General Manager to Refinery Manager.

The following comments are taken from Attachment 1 to the letter:

Comments 1, 3, 5, 7, 9, 11, 13, 14, 16, 18, 19, 20, 21, 22, 23, 24, 25, 27, 29, 31, 33, 35, 40, 41, 44, 64, 66, 70, 71, 72, 73, 80: Correct O2 monitoring type in Section VII to “O2 monitor”, since heater is equipped with an O2 concentration monitor, but not an O2 emissions monitor.

Response: Correction made to Table VII-A.1, A.2, A.3, A.4, A.5, A.6, A.7, A.8, A.9, A.10, A.11, A.12, A.13, A.14, A.15, A.16, A.17, A.18, A.20, A.21, A.22, A.23, A.24, A.25, A.26, A.29, A.30, A.31, A.32, A.33, A.34, A.35.

Comments 2, 4, 6, 8, 12, 15, 17, 26, 28, 30, 32, 34, 63, 65: Correct O2 monitoring frequency to C since heater is equipped with a continuous O2 monitor.

Response: Correction made to Table VII-A.2, A.3, A.4, A.5, A.7, A.9, A.10, A.18, A.20, A.21, A.22, A.23, A.29, A.30.

Comments 10, 39, 42, 43, 69, 79: Delete references to “CEM for NOx and O2 (or CO2)”. These CEMS are required by Regulation 1-520.8 because they are required by permit conditions (2-1-403).

Response: The comment notes that this requirement was deleted for some other sources. Those other sources were not required to have CEMs *by permit conditions*. The sources which still have this requirement are required to have CEMs by permit conditions. However, the effect of this requirement is simply to ensure that the CEM requirements in Reg 1-522 are followed. Because all sources with CEMs have Reg 1-522 listed as an applicable requirement, this citation is redundant and will be deleted from the sources noted. This affects Tables VII-A-6, VII-A.24, VII-A.25, VII-A.26, VII-A.31 and VII-A.35.

Comment 36: Change name of S-36.

Response: The applicant has changed the identifying unit name of this new heater from what was proposed in Application 5814. This change has been made in Tables II-A, IV-A.24 and VII-A.24.

Comment 37: Change future effectiveness date in Tables IV-A.24 and VII-A.24 from "startup date" to "after initial performance test" for Condition 21097, Parts 3a (abatement requirement) and 3b (emission rate limits) to allow initial adjustment of this new unit.

Response: This change has been made.

Comment 38: Change Condition 21097, Part 3b to indicate that Part 3a and 3b apply after the initial performance test.

Response: The condition already indicates this for Part 3b. However, unless it also refers to Part 3a, this startup allowance is not useable. This is a clarification of the obvious intent of the condition rather than an amendment. This change has been made to Condition 21097.

Comments 45, 46, 47 and 48: Move tanks S-107 and S-124 from Tables IV-B18 and VII-B18 to Tables IV-B13 and VII-B13 because these tanks have been retrofitted with superior zero-gap seals.

Response: These tanks belong in the indicated tables and these changes have been made.

Comments 49, 50, 51: Change description of tanks S-126, S-257 and S-258 to "internal floating roof tank with dome roof".

Response: This change was previously made in response to 12/24/03 e-mail.

Comment 52: Correct typo in Table IV-L.

Response: Corrected.

Comment 53: Correct citation to Condition 21092 in Table VII-L to refer to Condition 18255.

Response: Corrected.

Comment 54, 55, 56: Sulfur plants S-1001, S-1002 and S-1003 have a future capacity of 271 long ton/day after modification in accordance with permit 5814. The sulfur pits (S-301, S-302 and S-303) should also have this future capacity since the pits handle the molten sulfur from the sulfur plants.

Response: This future capacity has been added to Table II-A for S-301, S-302 and S-303.

Comment 57, 58 and 59: Sulfur plants S-1001, S-1002 and S-1003 have a future annual throughput of 98,915 long ton/yr after modification in accordance with permit 5814. The sulfur pits (S-301, S-302 and S-303) should also have this future throughput since the pits handle the molten sulfur from the sulfur plants.

Response: This future throughput has been added to Condition 20989 for S-301, S-302 and S-303.

Comment 60, 61 and 62: Sulfur plants S-1001, S-1002 and S-1003 and sulfur pits S-301, S-302 and S-303 have a future annual throughput of 98,915 long ton/yr after modification in accordance with permit 5814. This should be reflected in Table VII-U.

Response: This future throughput has been added to Table VII-U.

Comment 67: Correct citation of Condition 21092 to refer to Condition 21093.

Response: Corrected.

Comment 68: Condition 383 and 21093 are duplicative and Condition 21093 should be deleted.

Response: Condition 21093 is deleted.

Comment 74: Change name of S-460 from ULSD Hydrotreater to Diesel Hydrotreater.

Response: Changed.

Comment 75: Change annual throughput for S-460 hydrotreater from 11.68 E 6 bbl to 12.8 E 6 bbl in Condition 20989.

Response: S-460 has a monthly throughput limit in Condition 21094. This limit obviates the need for an annual limit. Therefore, S-460 has been deleted from Condition 20989 and references to Condition 20989 (related to S-460) have been deleted from Tables IV-N and VII-N.

Comment 76: Change name of S-461.

Response: The applicant has changed the identifying unit name of this new heater from what was proposed in Application 5814. This change has been made in Tables II-A, IV-A.35 and VII-A.35.

Comment 77: Change future effectiveness date in Tables IV-A.35 and VII-A.35 from "startup date" to "after initial performance test" for Condition 21096, Parts 3a (abatement requirement) and 3b (emission rate limits) to allow initial adjustment of this new unit.

Response: This change has been made.

Comment 78: Change Condition 21096, Part 3b to indicate that Part 3a and 3b apply after the initial performance test.

Response: The condition already indicates this for Part 3b. However, unless it also refers to Part 3a, this startup allowance is not useable. This is a clarification of the obvious intent of the condition rather than an amendment. This change has been made to Condition 21096.

Comments 81, 82: Change units for S-463 throughput in Condition 20989 from pounds to barrels for consistency with Table II-A. (1,000 bbl/day)(365 day/yr) = 365,000 bbl/yr

Response: This change has been made to Condition 20989 and Table VII-Y.

Comments 83, 84, 85: Same as Comments 60, 61, 62.

Response: Addressed in response to Comments 60, 61, 62.

Comment 86: Move permit shield in Table IX-B.1 (and delete this table) to Table IX-A.1.

Response: This change was previously made in response to 12/24/03 e-mail.

APPENDIX I

12/24/03 e-mail from ConocoPhillips

From: Uyeda, Valerie: [Valerie.J.Uyeda@conocophillips.com]
Sent: Wednesday, December 24, 2003 1:18 PM
To: Julian Elliot
Cc: Stern, Philip
Subject: Permit revisions

Hi Julian:

Thanks for meeting with Phil and me yesterday. As we discussed, here is the language that explains S-319 (U-215 gasoline fractionation unit). We propose to eliminate the S-319 throughput altogether and use the throughput for S-350 (U-267). See below for explanation:

U-215 is a gasoline refractionation unit. Drawings from 1973 listed the design rate as 14,000 B/D. It is a grandfathered unit with current hydraulic capacity estimated at 9,600 B/D.

In 1985, the Rodeo Refinery submitted a permit application to the BAAQMD to replace Crude Unit 67 with new Crude Unit 267 (S-350). This modification resulted in Gasoline Fractionation Unit 215 having one distillation tower and a fired heater shut down. This change in operation essentially converted U-215 into the light ends fractionation section of U-267. The only feed stream to U-215 is light gasoline from U-267. There are no process heaters in U-215 - all heat input is from steam reboilers.

U-215 instrument controls are not wired to the U-267 control room. A separate control room with an on-site operator is maintained in the U-215 area.

Since the only emission sources from U-215 are fugitive emissions and the feed rate is determined by U-267 feed rate and crude type, U-215 throughput should be tied to the U-267 throughput limit. Eliminating U-215 as a separate source number and including the fugitive sources for U-215 as part of U-267 would accomplish this.

I have also attached the Tables that were referenced in Attachment 1A and Attachment 1B that we discussed yesterday. For ease, I have also attached Attachment 1A and 1B.

I'll be in the office on 12/26 and then out until 1/5/04. Have a happy holiday.

<<Attachment 1 SFR 12_03 Corrections.doc>> <<Attachment 2 thru 5 SFR 12_03 Corrections.doc>>

- Val -

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rc (with attachments): 05-A-01-B Title V Permit Corrections
keywords: S-319, U-215

rc (without attachments): 03-215-02-A Title V Permit Throughput Correction

Comment Number	Source	Section	Table Number	Applicable Requirement	Proposed Change	Rationale
1	S-296 (Main Flare)	VI	Permit Conditions	PC 18255	Change	PC 18255, Part 3 should apply only to S-398. S-296 is not NSPS J flare.
2	S-296 (Main Flare), S-398 (MP-30 Flare)	VI	Permit Conditions	PC 18255	Delete	Alternate language was proposed in comments to BAAQMD dated September 19, 2003.
3	S-319 (U-215 Gasoline Fractionation)	II	A	Throughput	Change	Daily limit of 7500 is too low. Source is grandfathered. Annual limit shows 4.32 E^6 bbls which is equivalent to 11836 bbls/day. Raise daily limit in Table II-A to equal the annual 11836.
4	S-324 (API)	IV	C	40 CFR 60 (QQQ)	Change	API separator has a fixed, not floating roof and table has been changed to reflect this correction. See Attachment 2.
5	S-324 (API)	VII	C	40 CFR 60 (QQQ)	Change	Delete the citation to 60.693-2(a)(2). This citation refers to a floating roof. API separator has a fixed roof. See Attachment 4.
6	S-324 (API)	IX	B-1	40 CFR 60 (QQQ)	Delete	Delete table in its entirety to correct permit shield. Added permit shield to Table IX A-1. See Attachment 3 and 5
7	S-324 (API)	IX	A-1	40 CFR 60 (QQQ)	Add	Delete Table IX-B1 in its entirety to correct permit shield. Added permit shield to Table IX A-1. See Attachment 3 and 5
8	Various	VI	Permit Condition	PC 20989 (Throughput Limits)	Change	Heading on Table for annual throughput limits is for any consecutive 12-month period unless otherwise specified. We disagree that the District may impose this limit retroactively.

Comment Number	Source	Section	Table Number	Applicable Requirement	Proposed Change	Rationale
9		VI	Permit Conditions	PC 20620	Change	Correct date in Basis to April 11, 2005. Currently reads: [Basis: 40 CFR 63, Subpart UUU) By April 11, 2004]
10	All Sources	VII	All Sources Facility Specific Generally Applicable Reqts	NESHAP Subpart FF	Delete	Delete "Monitoring Requirement Citation" NESHAP Subpart FF 61.350, 61.356(k) and 61.357(d)(8) from VOC limit in Table VII. During the Title V Draft permit review, Table VII the "Citation of Limit" column for VOCs was corrected to remove the reference to NESHAP Subpart FF 61.342(a)(2) but the corresponding monitoring requirement was not corrected.
11	S-15 (U-244, B-501)	VII	A.13	PC 20989	Change	PC 20989 Part A in Table VII A.13 should be changed from an individual limit of 6.0 E6 therms/yr to a group limit of 19.9 E6 therms/yr for S-15, S-16, S-17, S-18, and S-19
12	S-16 (U244, B-502)	VII	A.14	PC 20989	Change	PC 20989 Part A in Table VII A.14 should be changed from an individual limit of 6.7 E6 therms/yr to a group limit of 19.9 E6 therms/yr for S-15, S-16, S-17, S-18, and S-19
13	S-17 (U244, B-503)	VII	A.15	PC 20989	Change	PC 20989 Part A in Table VII A.15 should be changed from an individual limit of 4.7 E6 therms/yr to a group limit of 19.9 E6 therms/yr for S-15, S-16, S-17, S-18, and S-19
14	S-18 (U244, B-504)	VII	A.16	PC 1694	Change	In Table IV-A.16, PC 1694 Part 1 federally enforceability is marked "N", this should be corrected accordingly in Table VII-A.16.

Comment Number	Source	Section	Table Number	Applicable Requirement	Proposed Change	Rationale
15	S-18 (U244, B-504)	VII	A.16	PC 20989	Change	PC 20989 Part A in Table VII A.16 should be changed from an individual limit of 1.9 E6 therms/yr to a group limit of 19.9 E6 therms/yr for S-15, S-16, S-17, S-18, and S-19
16	S-19 (U244, B-505)	VII	A.17	PC 20989	Change	PC 20989 Part A in Table VII A.17 should be changed from an individual limit of 0.6 E6 therms/yr to a group limit of 19.9 E6 therms/yr for S-15, S-16, S-17, S-18, and S-19
17	S-50, S-51, S-52	VI	Permit Conditions	PC 19488	Change	PC 19488 parts 1 & 2 apply only to S-50, S-51, and S-52. Change heading for these parts to reflect applicability. Heading includes S-53, 54, 55, 56, 57, and 58 incorrectly.
18	S-126 (Tk 172)	II	A		Change	Tank should be changed from "External Floating Roof" to "Internal Floating Roof with Dome" to match heading in Table VII B10
19	S-133 (Tk 193)	VII	B.16	BAAQMD 8-5-501.2	Change	Change monitoring frequency from "Periodic after each tank seal inspection" to "Periodic after each tank seal replacement". Table VII B.6 shows the correct monitoring frequency for this citation.
20	S-134 (Tk 194)	VII	B.20	BAAQMD 8-5-501.2	Change	Change monitoring frequency from "Periodic after each tank seal inspection" to "Periodic after each tank seal replacement". Table VII B.6 shows the correct monitoring frequency for this citation.
21	S-216 (Tk 695)	VII	B.19	BAAQMD 8-5-501.2	Change	Change monitoring frequency from "Periodic after each tank seal inspection" to "Periodic after each tank seal replacement". Table VII B.6 shows the correct monitoring frequency for this citation.

Comment Number	Source	Section	Table Number	Applicable Requirement	Proposed Change	Rationale
22	S-257 (Tk 1004)	II	A		Change	Tank should be changed from “External Floating Roof” to “Internal Floating Roof with Dome” to match heading in Table VII B10
23	S-258 (Tk 1005)	II	A		Change	Tank should be changed from “External Floating Roof” to “Internal Floating Roof with Dome” to match heading in Table VII B10
24	S-294 (Gas Dispenser)	IV	K	PC 18680	Change	Table contains a typo. BAAQMD Condition 7523 is listed twice in this Table. PC 7523 Part 1 should be for PC 18680 Part 1.
25	S-294 (Gas Dispenser)	VI	Permit Conditions	PC 18680	Add	Add heading to PC 18680 to clarify that permit condition applies to S-294
26	S-300 (U-200)	VI	Permit Conditions	PC 476	Add	Add heading to PC 476 to clarify that permit condition applies to S-300.
27	S-301, S-302, S-303, S-1001, S-1002, S-1003 (Sulfur Plant & Pits)	IV	U	PC 20620	Change	Table contains a typo. PC 20620 part 2 requires submission of an **Operation, Maintenance, and Monitoring Plan**, not a Startup, Shutdown, and Malfunction Plan.
28	S-305 (U-230)	VI	Permit Condition	PC 20989	Change	Annual limit should be 9.23 E^6 bbls. 25300 bbls * 365 days = 9234500.
29	S-307, S-308	IV	N	PC 20620	Change	Table contains a typo. PC 20620 part 2 requires submission of an **Operation, Maintenance, and Monitoring Plan**, not a Startup, Shutdown, and Malfunction Plan.

Comment Number	Source	Section	Table Number	Applicable Requirement	Proposed Change	Rationale
30	S-340 (Tk 108)	VII	B.17	BAAQMD 8-5-501.2	Change	Change monitoring frequency from “Periodic after each tank seal inspection” to “Periodic after each tank seal replacement”. Table VII B.6 shows the correct monitoring frequency for this citation.
31	S-350 (U-267)	IV	O	PC 383	Change	PC 383 Part 1b refers to Daily crude analysis requirement. Requirement is for each new tanker shipment or pipeline delivery. Remove the term “Daily”.
32	S-350 (U-267)	VII	O	PC 383	Change	Change frequency from P/D to P/E for PC 383, Part 1b. Requirement is to sample and analyze sulfur content each time a new tanker shipment or pipeline delivery of crude is introduced into the S-350 feed tanks, not daily.
33	S-448 (Tk 1007)	VII	B.9	BAAQMD 8-5-501.2	Change	Change monitoring frequency from “Periodic after each tank seal inspection” to “Periodic after each tank seal replacement”. Table VII B.6 shows the correct monitoring frequency for this citation.
34	Various tanks	VII	B.7	BAAQMD 8-5-501.2	Change	Change monitoring frequency from “Periodic after each tank seal inspection” to “Periodic after each tank seal replacement”. Table VII B.6 shows the correct monitoring frequency for this citation.
35	Various tanks	VII	B.10	BAAQMD 8-5-501.2	Change	Change monitoring frequency from “Periodic after each tank seal inspection” to “Periodic after each tank seal replacement”. Table VII B.6 shows the correct monitoring frequency for this citation.

Comment Number	Source	Section	Table Number	Applicable Requirement	Proposed Change	Rationale
36	Various tanks	VII	B.13	BAAQMD 8-5-501.2	Change	Change monitoring frequency from "Periodic after each tank seal inspection" to "Periodic after each tank seal replacement". Table VII B.6 shows the correct monitoring frequency for this citation.
37	Various tanks	VII	B.14	BAAQMD 8-5-501.2	Change	Change monitoring frequency from "Periodic after each tank seal inspection" to "Periodic after each tank seal replacement". Table VII B.6 shows the correct monitoring frequency for this citation.
38	Various tanks	VII	B.18	BAAQMD 8-5-501.2	Change	Change monitoring frequency from "Periodic after each tank seal inspection" to "Periodic after each tank seal replacement". Table VII B.6 shows the correct monitoring frequency for this citation.
39	Various tanks	VII	B.23B	BAAQMD 8-5-501.2	Change	Change monitoring frequency from "Periodic after each tank seal inspection" to "Periodic after each tank seal replacement". Table VII B.6 shows the correct monitoring frequency for this citation.

Table IV - C
Source-specific Applicable Requirements
S-324 API OIL/WASTEWATER SEPARATOR

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Regulation 8, Rule 8	**Wastewater (Oil-Water) Separator (6/15/94)**	**N**	
8-8-113	Exemption, secondary wastewater treatment processes and storm water sewer systems	Y	
8-8-114	Exemption, bypassed oil-water separator or air flotation influent	Y	
8-8-302	Wastewater separators rated capacity larger than or equal to 18.9 liters per seconds (300 gal/min), must be equipped with one of the following:	Y	
8-8-302.1	a solid, vapor-tight, full contact fixed cover which totally encloses the separator tank, chamber, or basin liquid contents, with all cover openings closed and sealed, except when the opening is being used for inspection, maintenance, or wastewater sampling.	Y	
8-8-306	Wastewater separator **effluent channels** rated capacity larger than or equal to 25.2 liters per second (400 gal/min) must be equipped with one of the following:	Y	
8-8-306.1	a solid, gasketed, fixed cover total enclosing the oil-water separator **effluent channel** liquid contents, with all cover openings closed, except when being used for inspection, maintenance, or wastewater sampling.	Y	
8-8-501	Maintain records when wastewater bypasses the API Separator or the Air Floatation Unit	Y	
8-8-503	Maintain records for semiannual gap inspections, closure requirements, and repairs for oil-water separator **effluent channel** fixed roof seals, access doors, and other openings.	Y	
NSPS 40 CFR 60 Subpart QQQ	**Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems**	**N**	
60.690(a)(1)	Applicability: Subpart QQQ applies to affected facilities constructed, modified, or reconstructed after May 4, 1987	Y	
60.690(a)(3)	An oil-water separator is a separate affected facility	Y	
60.692-1(a)	The provisions of Subpart QQQ apply except during periods of startup, shutdown, or malfunction	Y	
60.692-1(b)	Determine compliance through review of records and reports, performance test results, and inspections	Y	

Table IV - C
Source-specific Applicable Requirements
S-324 API Oil/Wastewater Separator

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
60.692-3 (a)	Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment shall be equipped and operated with a fixed roof which meets the following specifications:	Y	
60.692-3 (a)(1)	The fixed roof shall completely cover the separator tank, slop oil tank, storage vessel or other auxiliary equipment.	Y	
60.692-3 (a)(2)	The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.	Y	
60.692-3 (a)(3)	Roof access doors or openings shall be gasketed, latched, and kept closed during operation, except during inspection and maintenance.	Y	
60.692-3 (a)(4)	Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter.	Y	
60.692-3 (a)(5)	When a broken seal or gasket or other problem is identified repairs shall be attempted as soon as practicable, but no later than 15 days later.	Y	
60.692-3 (e)	Slop oil from an oil-water separator and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system.	Y	
60.692-6(a)	Delay of repairs are allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown.	Y	
60.692-6(b)	Delayed repairs shall be completed before the end of the next refinery or process unit shutdown.	Y	
60.697(a)	Each owner or operator shall comply with the recordkeeping provisions of Subpart QQQ.	Y	
60.697(c)	Record the location, date, and corrective action for inspections required by 60.692-3(a) when a problem is identified that could result in VOC emissions.	Y	
60.697(e)(1)	If an emission point cannot be repaired or corrected without a process unit shutdown, record the expected date of a successful repair.	Y	
60.697(e)(2)	The reason for the delay as specified in 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.	Y	
60.697(e)(3)	The signature of the owner or operator whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.	Y	
60.697(e)(4)	The date of successful repair or corrective action shall be recorded.	Y	
60.697(f)(1)	A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.	Y	

Table IV - C
Source-specific Applicable Requirements
S-324 API Oil/Wastewater Separator

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
60.697(f)(2)	Detailed information pertaining to the design specifications shall be kept.	Y	
60.698(b)(1)	Submit semiannually to the Administrator a certification that all of the required inspection have been carried out in accordance with Subpart QQQ standards.	Y	
60.698(c)	Submit semiannually to the Administrator a report that summarizes all inspections when cracks, gaps, or other problems that could result in VOC emissions are identified, including information about the repairs or corrective actions taken	Y	
BAAQMD Condition 1440			
Part 1	No vapor space in separator [Basis: Cumulative Increase]	Y	
Part 4a	No detectable VOC from doors, hatches, covers or other openings [Basis: Cumulative Increase]	Y	
Part 5	Semiannual VOC monitoring and records [Basis: Cumulative Increase]	Y	
Part 6	Maximum wastewater throughput [Basis: Cumulative Increase]	Y	
BAAQMD Condition 20989, Part A	Throughput limit for source S-324	Y	

Table IX B - 1
Permit Shield for Subsumed Requirements
S-324 API OIL/WASTEWATER SEPARATOR

Subsumed Requirement Citation	Title or Description	Streamlined Requirements	Title or Description
	.		

Table VII - C
Applicable Limits and Compliance Monitoring Requirements
S-324 API OIL/WASTEWATER SEPARATOR

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
VOC	BAAQMD Condition 1440, Part 4.a	Y		no detectable VOC emissions	BAAQMD Condition 1440, Part 5	P/SA	VOC analyzer
VOC	BAAQMD 8-8-306.1	Y		No cracks or gaps in roof seals, acess doors, and other openings in the **effluent channel** greater than 0.32 cm (0.125 inch) between the roof and wall	BAAQMD 8-8-306.1	P/SA	Visual inspections
VOC	NSPS Subpart QQQ, 40 CFR 60.692-3(a)	Y		Fixed roof access doors or openings shall be gasketed, latched, and kept closed	NSPS Subpart QQQ, 40 CFR 60.692-3(a)(4)	P/SA	Visual inspections
through-put	BAAQMD Condition 1440, Part 6	Y		maximum design throughput - 7,500 gpm during media filter backwash and 7,000 gpm during all other times	None	N	None
Through-put	BAAQMD Condition 20989, Part A	Y		3.68 E 9 gal/yr	BAAQMD Condition 20989, Part A	P/M	records

Table IX A - 1
Permit Shield for Non-applicable Requirements
ALL SOURCES

Citation	Title or Description (Reason not applicable)
BAAQMD Regulation 8, Rule 51	**"Organic Compounds – Adhesive and Sealant Products" (7/17/02)** The applicant has certified that none of the regulated activities specified in this rule are currently taking place at this facility.
BAAQMD Regulation 11, Rule 1	**"Hazardous Pollutants – Lead" (3/17/82)** The applicant has certified that there are no sources at this facility with the potential to emit in excess of 15 pounds per day (11-1-301) each, or with the potential to result in ground level lead concentrations in excess of 1.0 microgram/m3 averaged over 24 hours (11-1-302).
40 CFR 60.692-3(b)	This subsection of NSPS Subpart QQQ requires vents on oil-water separators to be routed through a closed vent system to a control device. The applicant's separator has a fixed roof that is in full contact with the liquid and does not contain any vents. As indicated in Table IV-C, applicant is subject to BAAQMD Regulation 8-8-302.1, which requires a "solid, vapor-tight, full contact cover which totally encloses the separator tank, chamber or basin (compartment) liquid contents, with all cover openings closed and sealed." Since no vents exist, there is nothing to route to a control device, so this subsection of Subpart QQQ does not apply.

APPENDIX J

4/13/04 letter from ConocoPhillips

APPENDIX K

10/31/03 letter from Gerardo Rios

October 31, 2003

Mr. Steve Hill
Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

RE: EPA Review of Proposed Refinery Title V/ Major Facility Review Permits: Conoco-Phillips Company (Rodeo) source # A0016, and Shell Martinez Refinery (Martinez) source # A0011

Dear Mr. Hill:

Thank you for the opportunity to comment on two proposed Bay Area Air Quality Management District ("BAAQMD" or "District") Title V Major Facility Review permits ("Title V permits"). We are submitting these comments now because we did not have enough time to review these two permits during the short EPA 45-day review period that ended on September 26, 2003 for all five proposed District refinery permits. We understand that the District will revise each proposed refinery permit as necessary to respond to the General Comments in our September 26, 2003 letter on the other three proposed refinery permits and we did not repeat those comments in today's letter.

We appreciate the District's willingness to review these comments prior to issuing the initial Title V permits for Conoco-Phillips and Shell Martinez. We recommend that the District include as many of the changes we are requesting as possible in the initial Title V permits, and make the rest of the recommended changes as soon as possible. As you know, EPA retains the authority to reopen any Title V permit if necessary to assure compliance with all applicable requirements and the requirements of 40 CFR part 70.

We appreciate the District's cooperation during this process. We understand that the District intends to proposed additional refinery Title V permit revisions in the near future, and we will continue to work cooperatively with the District during these revisions. If you have any questions concerning our comments, please contact me at (415) 972-3974, or contact Ed Pike of my staff at (415) 972-3970.

Sincerely,

Original signed by

Gerardo C. Rios
Chief, Air Permits Office

Adams, Broadwell, Joseph & Cardozo - Daniel Cardozo, et. al.
California Air Resources Board - Mike Tollstrup
Communities for a Better Environment - Will Rostov
Conoco-Phillips Company - Willie W. C. Chiang
Golden Gate University - Marcie Keever, et al
Shell Martinez Refinery - Aamir Farid

Enclosure A
EPA Comments on Conoco Phillips Refinery Permit

STATUS OF EPA REVIEW
EPA is providing comments now based on our limited review of the proposed permit so that the District will have time to review our comments prior to issuing the initial Title V permit. We will inform you if we have any additional comments in the future.

Our September 26, 2003 letter contains several general issues that are potentially applicable to all five proposed refinery permits including this proposed permit. Please note that today's comments are not intended to replace or repeat those comments.

ABATEMENT DEVICES
Monitoring

1. For abatement devices A-20 and A-21, the limits for differential pressure are specified as the "normal range"(Table IIB, page 19). Because the permit does not state what the "normal range" for the differential pressure is, these limits do not establish clear requirements for the source. EPA strongly recommends that these generic limits be replaced by the specific numerical values that constitute the allowable range of differential pressures. 1

2. The only monitoring included in the permit for sources 380 and 389 is measurement of the differential pressure across the sources' abatement devices. EPA recommends adding additional requirements for visual inspections on an event basis whenever visible emissions are seen exiting the silos. 2

COMBUSTION UNITS
Applicable Requirements

1. The note regarding Condition 1694 says that the original version of Part 5 of the condition was deleted because fuel oil is not burned at the facility and the condition is not needed. According to Condition A.2b, however, sources 3 and 7 are permitted to use liquid fuel. Unless the facility is prohibited from firing fuel oil, the original fuel oil conditions and the necessary monitoring requirements should remain in the permit. 3

2. According to Part B1 of Condition 476, the charging rate for source 300 has a daily limit of 56,000 barrels and an annualized daily limit of 52,000 barrels. Only the 56,000 barrel limit is listed in Table IIA on page 10 of the permit. This table should be revised to also include the annualized daily limit. 4

3. BAAQMD Regulation 9-3-303 was potentially omitted from the permit for sources 8 and 14. The District should review the applicability of this requirement for these units and revise the permit as appropriate. 5

4. Condition #1694, Part A.2b requires that sources 3 and 7 be monitored for visible emissions during tube cleaning (page 255). This applicable requirement was not included in Tables VII - A.2 and VII - A.5 and should be added. 6

5. Condition # 1694, Part A.2c requires that sources 3 and 7 be monitored for visible emissions before each 1 million gallons of liquid fuel is combusted at each source. The condition also requires a Method 9 evaluation if visible emissions are present. These requirements were not included in Tables VII - A.2 and VII - A.5 and should be added. 7

Federal Enforceability

Throughput Limits established in permit condition 1694:

In this permit, the District has proposed to change the designation for fuel limits that apply to most combustion sources from federally enforceable to not federally enforceable (for example, see Condition 1694 in Table IV - A.2 for source S-3; similar conditions exist for sources S-4 up to S-31 and all of the combustion units other than gas turbines and duct burners). The throughput limits in condition 1694 were established in a prior permitting action, although the permit and the Statement of Basis do not appear to discuss the type of permit nor the reason for marking them non-federally enforceable. Limits created through prior NSR permits are federally enforceable Title V permit requirements. Please see the enclosed March 31, 1999 letter from John Seitz, Director of EPA's Office of Air Quality Planning and Standards, to Doug Allard, CAPCOA President. 8

In addition, the throughput for S-10 in condition 1694 was increased from 184 to 223 mmbtu/hr without an explanation. The District should retain the 184 mmbtu/hr limit or justify the change. 9

Monitoring

The BAAQMD Continuous Emission Monitoring Policy and Procedures manual is designated as non-federally enforceable throughout the permit (for example, see Table IV - A.6 for source S-8 on page 43). This manual was approved into the SIP on 05/03/1984 and is therefore a federally enforceable requirement. The District should revise the permit accordingly. 10

COOLING TOWERS

Applicable Requirements

It appears that the cooling towers and all of their applicable requirements were omitted from the draft permit (except for BAAQMD Regulation 11, Rule 10 on page 24). The 11 cooling towers listed in the cooling tower calculations (and any additional towers not included in the calculations) should be incorporated into the permit.

Miscellaneous

Several sources are included in the cooling tower calculations but are listed in the permit as units other than cooling towers. For each of the following, the District should revise the permit and/or the calculations to reflect the true nature of the sources: 12

a. Source 110 - listed in the permit as tank 155 (see permit pages 9, 196, 197, 198 for example). 12a

b. Source 228 - listed in the permit as tank 750. In addition, the statement of basis notes that this unit has been removed from service. If this is the case, the permit should be updated to reflect the change. 13

c. Source 230 - listed in the permit as tank 752. In addition, the statement of basis notes that this unit has been removed from service. If this is the case, the permit should be updated to reflect the change. 14

d. Source 236 - listed in the permit as tank 770 (see permit pages 22, 246, and 408). 15

e. Source 238 - listed in the permit as Used Caustic Tank T-211 (see permit pages 9, 164, 294, and 374). 16

f. Source 240 - listed in the permit as tank 774. In addition, the Statement Of Basis notes that this unit has been removed from service. If this is the case, the permit should be updated to reflect the change. 17

<u>FUGITIVE SOURCES (PRESSURE RELIEF VALVES, PUMPS, COMPRESSORS)</u>

Applicable Requirements

1. Table IV - AA indicates that 40 CFR 61 Subpart V is neither applicable on a refinery-wide basis nor to any of the sources that are individually listed and it is unclear in the permit why. The standard would apply to any piece of equipment that contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP), such as benzene, unless the facility has demonstrated that the standard doesn't apply under 61.285(d). The District should re-evaluate the applicability of this subpart with respect to the fugitive emission sources at the refinery and include all appropriate applicable requirements. If the refinery or any sources are not subject to the subpart, a justification should be provided in the statement of basis. 18

2. Table IV-AB shows that NSPS Subpart QQQ is applicable to source 1007 (page 145). As a result this source should also be added to table IV-AA. 19

3. According to Table IV-B5, source 388 is subject to Part 3 of Condition 1860, which requires that the source be included in the fugitive emission monitoring program required by Regulation 8-18. This source and condition are not included in Table IV-AA and should be added. 20

4. Table IV-AA indicates that source 324 is subject to the requirements of 40 CFR 60 Subpart QQQ (page 142). This source should be specifically listed in Table IV-AB as a unit that is subject to Subpart QQQ along with source 1007 on page 145. 21

5. Table IV-AB is missing applicable requirements from 40 CFR 60 Subpart VV. The following should be added to the permit: 22
   60.482-2(c) - Pump leak repair period
   60.482-7(d) - Valve leak repair period

6. Table IV-AB is missing an applicable requirements from 40 CFR 63 Subpart CC. The following should be added to the permit: 23
   63.648(d) - New sources

Federal Enforceability

The 11/27/02 amendment to BAAQMD Regulation 8-18 has been approved in the SIP. Therefore, requirements 8-18-405 and 8-18-406 should be denoted as federally enforceable in Table IV-AB on page 143 of the permit. Upon doing so, the District should also delete the redundant requirements for SIP Regulation 8-18 from the same page. 24

Monitoring

We understand that the District will require the refineries to demonstrate compliance with SIP Regulation 8-10 by monitoring the pressure of all of the pressure vessels. 25

Miscellaneous

The adoption date for SIP 8-28 was misprinted in Table IV-AB on page 144. The date should be changed from 12/9/94 to 6/01/94. 26

<u>**HYDROGEN PLANT**</u>

Monitoring

Pursuant to BAAQMD Condition 6671 and Regulation 8-2-301, source 307 has a vent scrubber (A-50) to meet a 15 lb/day POC limit from emission streams with more than 300 ppm total carbon. EPA agrees that the rule limits are necessary for hydrogen plants at each of the refineries because hydrogen plant vents (presumably CO_2 vents) can emit over 15 lbs/day. We also believe that parameter monitoring to ensure proper operation of the control device is necessary and that testing will be necessary if the facility is not well under its emission limits (see Table VII-N, which only requirements for visual 27 inspection). We also believe that Reg 8-2 and monitoring requirements should apply to the CO2 vent at the hydrogen plant for each refinery.

LOADING RACKS

Monitoring

1. According to Table II B, the marine terminal thermal oxidizer must meet either of two limits: 28
   1) 2 pounds POC per 1,000 barrels loaded; or
   2) achieve a reduction of POC emissions of at least 95% by weight.

To demonstrate compliance with the above limits, Table VII - S (page 347) requires continuous monitoring of the device's temperature. EPA recommends adding a requirement for an appropriate residence time (with a gas flow meter as a monitoring method for the flow rate) to help ensure that the oxidizer meets the required control efficiency.

PERMIT SHIELDS

Applicable Requirements

The proposed permit contains a "subsumed requirements" permit shield from the floating roof tank requirements based on a request from Unocal in 1987 for alternate NSPS QQQ conditions. We were not able to locate an EPA approval document in the limited amount of time available to review this permit. Please remove the shield or provide us with a copy of the EPA approval document or the date and name of person who approved it. 29

TANKS

Applicable Requirements

For sources subject to NSPS Subpart Kb, the frequency specified for inspections of the secondary rim seal is not consistent with the regulations. The permits require inspections for holes or tears of the secondary rim seal at a frequency of once every ten years. However, pursuant to 60.113b(a)(2), the secondary seal should be inspected for holes, tears, or detachment on an annual basis. For example, see Table VII-B9 for source 448 in the permit. 30

Monitoring

1. The frequency specified for multiple tank monitoring requirements in the permit is "not specified." In cases where the monitoring frequencies are not specified in the applicable requirements, the District should use its periodic monitoring authority to establish appropriate ones. Occurrences of the unspecified monitoring frequency were noted in tables VII - B11, VII - B12, VII - B15, and VII - B25. Also note that the unspecified frequency occurs in Table VII - Cluster 11 in the Tesoro permit and Table VII.F.1.7 in the Chevron permit. 31

2. For tanks that are exempt from Regulation 8-5 based on low vapor pressure, the District requires monitoring of the vapor pressure only when there is a change in the material that is stored (see monitoring requirements for source 118 in Table 32
VII-B2 for example). In such cases, the District should establish what conditions or circumstances constitute a "material change." For example, crude oil that comes from one location can have a different vapor pressure than oil that comes from a different source. Without a clear definition of a "material change," the facilities may not consider such an event to be cause for a vapor pressure determination. In addition, for these sources, the District should require that the facilities maintain records of the tank contents.

GENERAL COMMENTS (UNSPECIFIED UNITS AND STATEMENT OF BASIS)

Unspecified Units

Applicable Requirements

1. Regulation 9-1-313.2 is marked non-federally enforceable in several instances 33
throughout the permit. This regulation is in the SIP and should be denoted federally enforceable in the permit.

Statement of Basis

Miscellaneous

1. The statement of basis says that permits may be revised through a variance or 34
an administrative change (page 12, electronic version). Please add to this discussion a clarification that any permit revisions made through a variance must go through the appropriate review process.

2. Section G of the statement of basis contains a brief summary of the changes made to the permit based on comments received by the District. The gener 35
response to comments document does not contain this type of summary, and we encourage the District to include this type of summary in the statement of basis or final response to comments for all five of the refinery permits.

APPENDIX L

4/14/04 letter from Gerardo Rios

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105

April 14, 2004

Mr. Steve Hill
Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

**RE: EPA Review of Draft Title V/ Major Facility Review Permits:
Chevron Products Company (Richmond) #A0010,
ConocoPhillips Company #A0016 (Rodeo),
Shell Oil Products US #A0011 (Martinez),
Tesoro Refining and Marketing Company (Martinez) #B2758 & B2759,
Valero Refining Company #B2626 (Benicia)**

Dear Mr. Hill:

We are enclosing with this letter our comments on the draft revised permits for Chevron Products Company; ConocoPhillips Company; Shell Oil Products US, Tesoro Refining and Marketing Company; and Valero Refining Company. Thank you for the opportunity to provide comments on these draft revised permits. We understand that the District will submit proposed revised permits to EPA pursuant to 40 CFR section 70.8. Please note that in addition to the comments we are submitting today, our review of the proposed revised permits may generate additional EPA comments.

We look forward to continuing to work with the District during this process. If you have any questions concerning our comments, please contact me at (415) 972-3974 or Ed Pike of the Permits Office at (415) 972-3970.

Sincerely,

Gerardo C. Rios
Chief, Air Permits Office

Enclosures

cc: Adams, Broadwell, Joseph & Cardozo - Daniel Cardozo, et. al.
California Air Resources Board - Mike Tollstrup
Chevron Products Company - Jim Whiteside
Communities for a Better Environment - Will Rostov
Conoco-Phillips Company - Willie W. C. Chiang
Golden Gate University - Marcie Keever, et al
Shell Martinez Refinery - Aamir Farid
Tesoro Refining and Marketing Company - J. W. Haywood
Valero Refining Company - Douglas Comeau

Enclosure E - ConocoPhillips
April 14, 2004 Update to EPA's October 31, 2003 Comments

Introduction
Please note that these comments are repeated from our October 30, 2003 letter, as we have not received a response to those comments. We have made a few deletions where we identified that changes were made for other reasons.

ABATEMENT DEVICES

Monitoring

1. For abatement devices A-20 and A-21, the limits for differential pressure are specified as the "normal range" in Table IIB. Because the permit does not state what the "normal range" for the differential pressure is, it does not establish clear requirements for the source. EPA recommends that these generic limits be replaced by the specific numerical values that constitute the allowable range of differential pressures.

2. The only monitoring included in the permit for S-380 and S-389 are quarterly inspections of the differential pressure across the sources' abatement devices. EPA recommends adding additional requirements for visual inspections on an event basis whenever visible emissions are seen exiting the silos.

COMBUSTION UNITS

Applicable Requirements
1. The note in the August 2003 draft permit regarding Condition #1694 says that the original version of Part 5 was deleted because fuel oil is not burned at the facility and the condition is not needed. According to Condition A.2b, however, Sources 3 and 7 are permitted to use liquid fuel. Regardless of current firing practices, as long as the

sources are allowed to burn liquid fuel, the original fuel oil limitation and any necessary monitoring requirements should remain in the permit.

2. Please explain the reason for raising the capacity of Source S-300 from 56,000 barrels to 81,000 barrels in Table IIA.

3. Condition #1694, Part A.2b requires that Sources 3 and 7 be monitored for visible emissions during tube cleaning. This applicable requirement should be added to Tables VII - A.2 and VII - A.5. In addition, the condition specifically says that visible emissions monitoring must be conducted during tube cleaning during daylight hours. It is possible to monitor for visible emissions at night. EPA recommends that monitoring for visible emissions be required any time tube cleaning is conducted. Alternatively, the District may restrict tube cleaning operations to daylight hours only.

New EPA Comment: Federal Enforceability
Throughput Limits established in permit Condition 1694: The District has changed the designation for fuel limits that apply to many combustion sources from federally enforceable to not federally enforceable (for example, see Condition #1694 in Table IV - A.2 for Source S-3; similar conditions exist for Sources S-4 through to S-31, and all of the combustion units other than gas turbines and duct burners). The throughput limits in Condition #1694 were established in a prior permitting action, although the permit and the Statement of Basis do not appear to discuss the type of permit nor the reason for marking them non-federally enforceable. Limits created through prior NSR permits are federally enforceable Title V permit requirements. Please see the enclosed March 31, 1999 letter from John Seitz, Director of EPA's Office of Air Quality Planning and Standards, to Doug Allard, CAPCOA President. [1]

In addition, the throughput for S-10 in Condition #1694 was increased from 184 to 223 MMBtu/hr without an explanation. The District should retain the 184 mmbtu/hr limit or justify the change.

Monitoring
The BAAQMD Continuous Emission Monitoring Policy and Procedures manual is designated as non-federally enforceable throughout the permit (for example, see Table IV - A.6 for Source S-8 on page 43). This manual was approved into the SIP on 05/03/1984 and is therefore a federally enforceable requirement. The District should revise the permit accordingly.

<u>COOLING TOWERS</u>

1Note that the referenced document was enclosed with our October 31, 2003 letter.

Enclosure E - Conoco-Phillips

Applicable Requirements

It appears the cooling towers and all of their applicable requirements were omitted from the draft permit (except for BAAQMD Regulation 11, Rule 10 on page 24). The cooling towers listed in the cooling tower calculations (and any additional towers not included in the calculations) should be incorporated into the permit.

Miscellaneous

Two sources are included in the cooling tower calculations but are listed in the permit as units other than cooling towers. For each of the following, the District should revise the permit or the calculations to reflect the true nature of the sources:

a. S-110 - listed in the permit as Tank 155
b. S-238 - listed in the permit as Used Caustic Tank T-211.

In addition, S-236 is included in the cooling tower calculations but is not in the permit.

FLARES and THERMAL OXIDIZERS

Because of the extent of the changes made to flare conditions in the refinery permits, EPA has reevaluated the permits with respect to flares and thermal oxidizers. Because of the complete rewriting of flare issues in the permits and EPA's reevaluation, we have removed our previous comments from enclosures B-F, and have addressed any outstanding issues from our original comments, as well as any issues regarding the District's revised flare conditions, in Enclosure A – General Comments.

FUGITIVE SOURCES (PRESSURE RELIEF VALVES, PUMPS, COMPRESSORS)

Applicable Requirements

1. Table IV - AA indicates that 40 CFR 61 Subpart V is neither applicable on a refinery-wide basis nor applicable to any of the sources that are individually listed. It is unclear why the District has made this conclusion. The District should re-evaluate the applicability of this subpart, include all appropriate applicable requirements in the permit, and provide EPA with a complete applicability determination.

2. Table IV-AB shows that NSPS Subpart QQQ is applicable to Source S-1007. This source should be added to Table IV-AA.

3. According to Table IV-B5, S-388 is subject to Part 3 of Condition #1860, which requires that the source be included in the fugitive emission monitoring program required by Regulation 8-18. This source and condition are not included in Table IV-AA and should be added.

4. Table IV-AA indicates that S-324 is subject to the requirements of 40 CFR 60 Subpart QQQ. This source should be identified in Table IV-AB as a unit that is subject to Subpart QQQ along with S-1007.

5. Table IV-AB is missing applicable requirements from 40 CFR 60 Subpart VV. The following should be added to the permit:
   60.482-2(c) - Pump leak repair period
   60.482-7(d) - Valve leak repair period

6. Table IV-AB is missing an applicable requirements from 40 CFR 63 Subpart CC. The following should be added to the permit, which applies to pumps and valves if the refinery has started up any new sources:
   63.648(d) - New sources

Federal Enforceability
The 11/27/02 amendment to BAAQMD Regulation 8-18 has been added to the SIP. Therefore, requirements 8-18-405 and 8-18-406 should be identified as federally enforceable in Table IV-AB. Upon doing so, the District should also delete the redundant requirements for SIP Regulation 8-18 from the table.

Monitoring
We understand that the District will require the refineries to demonstrate compliance with SIP Regulation 8-10 by monitoring the pressure of all of the pressure vessels.

Miscellaneous
The adoption date for SIP 8-28 was misprinted in Table IV-AB on page 144. The date should be changed from 12/9/94 to 6/1/94.

HYDROGEN PLANT

Monitoring
Pursuant to BAAQMD Condition #6671 and Regulation 8-2-301, S307 has a vent scrubber (A-50) to meet a 15 lb/day POC limit from emission streams with more than 300 ppm total carbon. EPA agrees that the rule limits are necessary for hydrogen plants at each of the refineries because hydrogen plant vents (presumably CO_2 vents) can emit over 15 lbs/day. We believe that parameter monitoring to ensure proper operation of the control device is necessary and that testing will be necessary if the facility is not well under its emission limits (see Table VII-N, which only has requirements for visual inspections). We also believe that Reg 8-2 and monitoring requirements should apply to the CO_2 vents at the hydrogen plants for each refinery.

LOADING RACKS

Monitoring
According to Table II B, the marine terminal thermal oxidizer, A-420, must meet either of two limits:

1) 2 pounds POC per 1,000 barrels loaded; or
2) achieve a reduction of POC emissions of at least 95% by weight.

To demonstrate compliance with the above limits, Table VII - S (page 347) requires continuous monitoring of the device's temperature. EPA recommends adding a requirement for an appropriate residence time (with a gas flow meter as a monitoring method for the flow rate) to help ensure that the oxidizer meets the required control efficiency.

PERMIT SHIELDS

The proposed permit contains a "subsumed requirements" permit shield from the floating roof tank requirements based on a request from Unocal in 1987 for alternate NSPS Subpart QQQ conditions. Please remove the shield or provide us with a copy of the EPA approval document, or the date and name of the person who approved it.[2]

TANKS
Monitoring

1. The frequency specified for multiple tank monitoring requirements in the permit is "not specified." In cases where the monitoring frequencies are not specified in the applicable requirements, the District should establish appropriate monitoring conditions. Occurrences of the unspecified monitoring frequency were noted in Tables VII - B11, VII - B12, VII - B15, and VII - B25.

2. For tanks that are exempt from Regulation 8-5, based on low vapor pressure, the District requires monitoring of the vapor pressure when there is a change in the type of material that is stored (see Condition #20773.1). The District should also require that initial vapor

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2*Update to October, 2003 comment:* The ConocoPhillips permit contains a shield based on a request from ConocoPhillips rather than EPA approval of their proposed alternative control. "As described in the NSPS Subpart QQQ Request for Alternative Standards pursuant to 40 CFR 60.693-2(b) and 60.694 submitted to USEPA by Unocal on December 28, 1987, in lieu of a floating roof equipped with a closure device, the separator would be equipped with the full contact fixed roof as an equivalent closure device." This permit shield has been reworded since our comment, but still does not have a valid basis. Alternatives under 40 CFR section 60.694 require publication in the Federal Register of EPA approval of the alternative, and there is no indication of any such notice for the concrete roof tank cited in Condition 1440 Part 1. Notification under 60.693-2(b) does not replace the requirement for approval by EPA for alternatives. Please delete the shield unless ConocoPhillips has received approval for their proposed alternate control.

pressure determinations be conducted to demonstrate initial compliance with the exemption. In addition, the condition says that if the results of the monitoring yield a vapor pressure greater than 0.5 psia, the Permittee must submit an application for a permit to operate for the tank "as quickly as possible." This requirement is not practically enforceable. The District should revise the condition so that it requires a permit application within a specific period of time.

APPENDIX M

5/27/04 Administrative Amendment to Permit