Bay Area Air Quality Management District

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San Francisco, CA 94109
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Permit Evaluation
and
Statement of Basis
for
Significant and Minor Revisions of

MAJOR FACILITY REVIEW PERMIT

for

ConocoPhillips Carbon Plant
Facility #A0022

Facility Address:
2101 Franklin Canyon Road
Rodeo, CA 94572

Mailing Address:
2101 Franklin Canyon Road
Rodeo, CA 94572

April, 2009

Application Engineer: Brenda Cabral
Site Engineer: Sanjeev Kamboj

Application: 17331

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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 Title 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 and more than 10 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.

Each facility in the Bay Area is assigned a facility identifier that consists of a letter and a 4-digit number. This identifier is also considered to be the identifier for the permit. The identifier for this facility is A0022.

This facility received its initial Title V permit on July 31, 2002. The permit has not been modified since it was issued.

This application is for a significant revision to the permit. This statement of basis will include all proposed changes to the permit in strikeout/underline format. This statement of basis addresses only the proposed changes to the permit. The statement of basis for the permit issued on July 31, 2002 contains the basis for the rest of the permit.

The purpose of this revision is to incorporate permit conditions that were imposed on the facility so that the facility could obtain SO2 offsets and "CEQA" PM10 offsets for the Clean Fuel Expansion Project (CFEP) at the ConocoPhillips Refinery, Facility A0016, which includes a hydrogen plant, Facility 17419. The Carbon Plant is owned and operated by the refinery and the two plants are contiguous, so offsets that are generated at Facility A0022 are valid for use by Facility A0016. The CFEP project is fully described in the engineering evaluations for Application 13424 and 13678, and the statements of basis for Applications 13427 and 14637.

Air Liquide is building a hydrogen plant that will receive raw materials from the refinery and produce hydrogen, steam, and electricity for the refinery. The District has determined that the hydrogen plant and associated equipment is part of the refinery. However, the District is issuing a separate permit to the hydrogen plant and compliance will be certified by a separate responsible official because different personnel will be in charge of operation. The hydrogen plant is considered to be under ConocoPhillips' control because the refinery will direct how much hydrogen the plant will make at any time and the hydrogen plant is on refinery property, completely surrounded by the refinery. Moreover, for the purposes of the New Source Review and Prevention of Significant Deterioration programs, the refinery's project and construction of the hydrogen plant are considered to be one project.

Following is the total change in emissions due to Application 13424.

Pollutant	Amount, tons/year
POC	-25.0
NOx	-25.1
SO2	35.6
CO	-2.5
PM10	0.7
NH3	6.35
H2SO4	6.3
H2S	1.0

Following is the total change in emissions due to Application 13678.

Pollutant	Amount, tons/year
POC	13.9
NOx	30.9
SO2	5.0
CO	46.2
PM10	13.8
NH3	26.9
H2S04	0.4

Following is the total change in emissions due to Application 15328.

Pollutant	Amount, tons/year
SO2	-42
PM10	-8

(Note: the decrease in PM10 emissions is not considered to be valid for the purpose of obtaining offsets pursuant to BAAQMD Regulation 2-2-201, but is valid for California CEQA purposes.)

Following is the total change in emissions for the whole project:

Pollutant	Amount, tons/year
POC	-11.1
NOx	5.8
SO2	-1.4
CO	43.7
PM10	14.5
NH3	33.3

Pollutant	Amount, tons/year
H_2SO_4	6.7
H_2S	1.0

The emissions are shown for the pollutants that the facilities will emit in quantities over one ton per year. The detail for other hazardous air pollutants is included in Applications 13424 and 13678, which form part of this statement of basis, and are included in Appendices C and D.

Additional changes

The name of the facility has been changed to ConocoPhillips Carbon Plant.

The responsible official has been changed from Willie C. W. Chiang to Rand Swenson at the facility's request.

This action also incorporates the establishment of allowable pressure drop ranges for S1 and S2, Kilns. The pressure drop ranges were submitted by ConocoPhillips on January 31, 2003, as required by BAAQMD Condition 136, part 8 (now part 11).

B. Facility Description

The ConocoPhillips Carbon Plant refines petroleum coke. The process used is as follows:

1. Petroleum coke is received from a refinery.
2. Coke is conveyed to the coke calciner where it is calcined (heated). This process removes impurities from the coke, including sulfur and water.
3. The hot waste gases from the calciner are sent to the pyroscrubber that removes particulate by a combination of settling and incineration. Sulfur compounds are oxidized to sulfur dioxide.
4. The hot waste gases are sent to a heat recovery steam generator for the production of steam for the generation of electricity. The cooled waste gases pass through a baghouse and tall stack and are then emitted into the atmosphere.
5. The resulting refined coke is sold.

C. Permit Content

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

I. Standard Conditions

This section contains administrative requirements and conditions that apply to all facilities.

Changes to permit

There are no changes to Section I in this action.

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).

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., A24). .

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 the permitted sources table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-403.

Changes to permit:
The sources and abatement devices below are the subject of this application.

Table II A - Permitted Sources

Each of the following sources has been issued a permit to operate pursuant to the requirements of BAAQMD Regulation 2, Permits. The capacities in this table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-301.

S-#	Description	Make or Type	Model	Capacity
S-1	K-1 Coke Calcine Kiln/Cooler, Natural gas fired, 62 MMBTU/HR	Traylor kiln with Procedair Industries burner	none	30 tons per hour and 262,800 tons per year of calcined petroleum coke: 620 therms per hour and 5.25 million therms per year of natural gas

Table II A - Permitted Sources

Each of the following sources has been issued a permit to operate pursuant to the requirements of BAAQMD Regulation 2, Permits. The capacities in this table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-301.

S-#	Description	Make or Type	Model	Capacity
S-2	K-2 Coke Calcine Kiln/Cooler, Natural gas fired, 62 MMBTU/HR	Traylor kiln with Procedair Industries burner	none	30 tons per hour and 262,800 tons per year of calcined petroleum coke; 620 therms per hour and 5.00 million therms per year of natural gas

BAAQMD Regulation 6, Particulate Matter, has been changed to Regulation 6, Particulate Matter, Rule 1, General Requirements. The citations of the rule will be changed for the sources affected by this action and during the Major Facility Review permit renewal for the remaining sources. Since the name and number of the rule in the State Implementation Plan (SIP) remained the same, citations of the SIP rule have been added.

No parameters are measured at the pyroscrubbers, A-1 and A-2, so the entry in the operating parameters column for the pyroscrubbers has been changed to “None.” The pressure drop is measured at the baghouses, A-10 and A-11. The parameter has been added to the operating parameters column.

The limit in Regulation 6-1-311, General Operations, has been described as “hourly PM limit based on throughput.” This limit is calculated using the process weight. However, the maximum emissions allowed are 40 lb of filterable particulate per hour, so this clarification has been added.

Table II B – Abatement Devices

A#	Description	Source(s) Controlled	Applicable Requirement	Operating Parameters	Limit or Efficiency
A-1	K-1 Pyroscrubber, Detrick 70’ by 22’ by 35’ Refractory Pyroscrubber with flat bottom, Natural gas fired (30 MMBTU/HR)	S-1, S-16, S-26 (S-16 and S-26 are first abated by A-12)	BAAQMD ~~6-~~6-1-301 & SIP 6-301	None ~~to be directly monitored (A-1 is abated by A-10 and pressure drop across A-10 to be determined)~~	Ringelmann 1.0 for < 3 minutes/hr
			BAAQMD ~~6-~~6-1-305 & SIP 6-305	None ~~to be directly monitored (A-1 is abated by A-10 and pressure drop across A-10 to be determined)~~	limit fallout of visible particles to on-site
			BAAQMD ~~6-~~6-1-310 & SIP 6-310	None ~~to be directly monitored (A-1 is abated by A-10 and pressure drop across A-10 to be determined)~~	343 mg per sdcm in exhaust
			BAAQMD ~~6-~~6-1-310.3 & SIP 6-310.3	None ~~to be directly monitored (A-1 is abated by A-10 and pressure drop across A-10 to be determined)~~	343 mg per sdcm in exhaust @ 6% oxygen
			BAAQMD ~~6-~~6-1-311 & SIP 6-311	None ~~to be directly monitored (A-1 is abated by A-10 and pressure drop across A-10 to be determined)~~	hourly PM limit based on throughput; maximum 40 lb/hr
A-2	K-2 Pyroscrubber, Detrick 70’ by 22’ by 35’ Refractory Pyroscrubber with flat bottom, Natural gas fired (30 MMBTU/HR)	S-2, S-17, S-27 (S-17 and S-27 are first abated by A-13)	BAAQMD ~~6-~~6-1-301 & SIP 6-301	None ~~to be directly monitored (A-2 is abated by A-11 and pressure drop across A-11 to be determined)~~	Ringelmann 1.0 for < 3 minutes/hr

Table II B – Abatement Devices

A#	Description	Source(s) Controlled	Applicable Requirement	Operating Parameters	Limit or Efficiency
A-2	K-2 Pyroscrubber, Detrick 70' by 22' by 35' Refractory Pyroscrubber with flat bottom, Natural gas fired (30 MMBTU/HR)	S-2, S-17, S-27 (S-17 and S-27 are first abated by A-13)	BAAQMD ~~6-~~6-1-305 & SIP 6-305	None ~~to be directly monitored (A-2 is abated by A-11 and pressure drop across A-11 to be determined)~~	limit fallout of visible particles to on-site
			BAAQMD ~~6-~~6-1-310 & SIP 6-310	None ~~to be directly monitored (A-2 is abated by A-11 and pressure drop across A-11 to be determined)~~	343 mg per sdcm in exhaust
			BAAQMD ~~6-~~6-1-310.3 & SIP 6-310.3	None ~~to be directly monitored (A-1 is abated by A-10 and pressure drop across A-10 to be Determined)~~	343 mg per sdcm in exhaust @ 6% oxygen
			BAAQMD ~~6-~~6-1-311 & SIP 6-311	***None*** ~~***to be directly monitored (A-2 is abated by A-11 and pressure drop across A-11 to be Determined)***~~	hourly PM limit based on throughput; maximum 40 lb/hr
A-10	K-1 Baghouse, Pulse Jet	S-1, S-16, S-26 (S-1 is first abated by A-1 and then A-14, S-16 and S-26 are first abated by A-12 and then A-1)	BAAQMD ~~6-~~6-1-301 & SIP 6-301	~~***Pressure drop to be determined***~~ Pressure drop between 4.5 and 7.0 inches of water gauge	Ringelmann 1.0 for < 3 minutes/hr

Table II B – Abatement Devices

A#	Description	Source(s) Controlled	Applicable Requirement	Operating Parameters	Limit or Efficiency
			BAAQMD ~~6-~~6-1-305 & SIP 6-305	Pressure drop between 4.5 and 7.0 inches of water gauge ~~***Pressure drop to be determined***~~	limit fallout of visible particles to on-site
			BAAQMD ~~6-~~6-1-310 & SIP 6-310	Pressure drop between 4.5 and 7.0 inches of water gauge ~~***Pressure drop to be determined***~~	343 mg per sdcm in exhaust
			BAAQMD ~~6-~~6-1-310.3 & SIP 6-310.3	Pressure drop between 4.5 and 7.0 inches of water gauge ~~***Pressure drop to be determined***~~	343 mg per sdcm in exhaust @ 6% oxygen
			BAAQMD ~~6-~~6-1-311 & SIP 6-311	Pressure drop between 4.5 and 7.0 inches of water gauge ~~***Pressure drop to be determined***~~	Hourly PM limit based on throughput; maximum 40 lb/hr
A-11	K-2 Baghouse, Pulse Jet	S-2, S-17, S-27 (S-2 is first abated by A-2 and then A-15, S-17 and S-27 are first abated by A-13 and then A-2)	BAAQMD ~~6-~~6-1-301 & SIP 6-301	Pressure drop between 4.5 and 7.0 inches of water gauge ~~***Pressure drop to be determined***~~	Ringelmann 1.0 for < 3 minutes/hr
			BAAQMD ~~6-~~6-1-305 & SIP 6-305	Pressure drop between 4.5 and 7.0 inches of water gauge ~~***Pressure drop to be determined***~~	limit fallout of visible particles to on-site

Table II B – Abatement Devices

A#	Description	Source(s) Controlled	Applicable Requirement	Operating Parameters	Limit or Efficiency
A-11	K-2 Baghouse, Pulse Jet		BAAQMD ~~6-~~6-1-310 & SIP 6-310	Pressure drop between 4.5 and 7.0 inches of water gauge~~***Pressure drop to be determined***~~	343 mg per sdcm in exhaust
			BAAQMD ~~6-~~6-1-310.3 & SIP 6-310.3	Pressure drop between 4.5 and 7.0 inches of water gauge~~***Pressure drop to be determined***~~	343 mg per sdcm in exhaust @ 6% oxygen
			BAAQMD ~~6-~~6-1-311 & SIP 6-311	Pressure drop between 4.5 and 7.0 inches of water gauge~~***Pressure drop to be determined***~~	hourly PM limit based on throughput; maximum 40 lb/hr
			Condition #136, part 10	Pressure drop between 4.5 and 7.0 inches of water gauge	29.4 tons PM10 in any 12-month period
A-14	K-1 Dry Sorbent Injection System	S-1 (S-1 is first abated by A-1)	None	None	None
A-15	K-2 Dry Sorbent Injection System	S-2 (S-2 is first abated by A-2)	~~None~~ Condition #136, part 5	None	~~None~~749.32 tons SO2 in any 12-month period

The basis for the new PM10 and SO2 limits in BAAQMD Condition 136, parts 5 and 10, is set out in the engineering evaluation for Application 15328, which forms part of this statement of basis and is attached in Appendix B.

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 significant sources pursuant to the definition in BAAQMD Rule 2-6-239.

Changes to permit
The web address for the State Implementation Plan, which is found on EPA Region IX's website, has been added as follows:

> The full language of SIP requirements is on EPA Region 9's website. The address is: http://yosemite.epa.gov/r9/r9sips.nsf/Agency?ReadForm&count=500&state=California&cat=Bay+Area+Air+Quality+Management+District-Agency-Wide+Provisions.

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) are listed following the corresponding District rules. SIP rules are District rules that have been approved by EPA for inclusion in 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 portion of the SIP rule is cited separately after the District rule. The SIP portion will be federally enforceable; the non-SIP version will not be federally enforceable, unless EPA has approved it through another program.
- Other District requirements, such as the Manual of Procedures, as appropriate.
- Federal requirements (other than SIP provisions)
- BAAQMD permit conditions. The text of BAAQMD permit conditions is found in Section VI of the permit.
- Federal permit conditions. The text of Federal permit conditions, if any, is found in Section VI of the permit.

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

The applicability of many requirements is discussed in the Engineering Evaluation for Application 13424. This statement of basis will only address items that are not addressed in the Engineering Evaluation.

Complex Applicability Determinations

S-1 and S-2, Calciners, are subject to 40 CFR 64, Compliance Assurance Monitoring (CAM) because they meet the criteria in Section 64.2(a). They use the pyroscrubbers, A-1 and A-2, the baghouses, A-10 and A-11, and the dry sorbent injection systems, A-14 and A-15, for compliance with the federally enforceable SO2 limits in BAAQMD Regulation 9-1-310.2 and the federally enforceable filterable particulate limits in BAAQMD Regulations 6-1-310, 6-1-310.3, and 6-1-311. The new annual SO2 limit in Condition #136, Part 5, is also a federally enforceable limit. The new PM10 limit in Condition #136, part 10, is not federally enforceable. The emissions of both SO2 and filterable particulate are more than 100 tons per year before abatement. The SO2 emissions are also more than 100 tons per year after abatement.

ConocoPhillips will comply with CAM for the SO2 limits because Section 64.3(d) allows the use of existing CEMs for compliance and Section 64.4(b)(2) acknowledges that CEMs are "presumptively acceptable."

However, the existing monitoring for particulate consists of weekly pressure drop measurements, quarterly visible emissions monitoring, and annual source tests and will not be adequate to comply with CAM requirements.

Therefore, the facility has proposed daily visible emissions monitoring in addition to the existing weekly pressure drop monitoring and the annual baghouse inspection. An annual source test for PM10 will also be required to ensure compliance with the annual PM10 limit. Where there is no direct measurement, the facility must use an "indicator" to determine that the control device is operating properly. The facility has proposed that the indicator is any visible emissions, which will considered to be a excursion pursuant to Section 64.6(c)(2). The visible emissions monitoring will be performed using EPA Method 22, which is more appropriate to determine whether there are any visible emissions, instead of the BAAQMD Method, "Evaluation of Visible Emissions." The BAAQMD method is appropriate for determining the opacity of the emissions.

The end of Section 64.3(a) states that: "In addition, unless specifically stated otherwise by an applicable requirement, the owner or operator shall monitor indicators to detect any bypass of the control device (or capture system) to the atmosphere, if such bypass can occur based on the design of the pollutant-specific emissions unit." Each kiln has a bypass stack prior to the pyroscrubbers.

ConocoPhillips will determine whether the bypass is in use by using the CEM to note changes in concentration and flow through the main stack. This monitoring will be added in Condition 136, part 3d.

Section 64.3(b)(4)(ii) requires that for sources where the emissions after control are more than 100 tons per year of the controlled regulated air pollutant, the monitoring method must collect four or more data points per hour and average the values. The SO2 emissions after control are more than 100 tons per year, therefore this requirement will be added as Condition #136, part 3c.

The facility uses the quality assurance procedures in the BAAQMD Manual of Procedures, Volume V, Continuous Emission Monitoring Policy and Procedures, for the SO2 CEM, so it will comply the requirement for quality assurance procedures in Section 64.3(b)(3).

Other Changes to permit

The web address for the State Implementation Plan, which is found on EPA Region IX's website, has been added as follows:

> The full language of SIP requirements is on EPA Region 9's website. The address is: http://yosemite.epa.gov/r9/r9sips.nsf/Agency?ReadForm&count=500&state=California&cat=Bay+Area+Air+Quality+Management+District-Agency-Wide+Provisions.

BAAQMD Regulation 6, Particulate Matter, has been changed to Regulation 6, Particulate Matter, Rule 1, General Requirements. The citations of the rule will be changed throughout the permit.

Following are the proposed changes for S-1 and S-2, Calciners.

Regulation 6, Particulate Matter and Visible Emissions, was renumbered as Regulation 6, Rule 1, and renamed as Particulate Matter, General Requirements on December 5, 2007. The equivalent rule in the State Implementation Plan (SIP) is Regulation 6, Particulate Matter and Visible Emissions, which was approved in a Federal Register notice of September 4, 1998.

Since the facility is monitoring the baghouses at S-1 and S-2 with pressure drop monitors, S-1 and S-2 are subject to the parametric monitoring requirements in BAAQMD Regulation 1-523. The SIP version has been included because it is different from the current District requirements.

The description of Condition #136, part 3b, has been improved.

ConocoPhillips agreed to source test the calciners to determine whether there was an increase in sulfuric acid mist (SAM) due to heat recovery. The requirement was added in Condition #136, part 6. The purpose was to resolve speculation that sulfuric acid mist could have increased by more than 7 tons per year in 1982 when the heat recovery system was installed. The source testing was completed by July 15, 2008. The only existing test had a result of 6.24 lb SAM/hr from S2, Kiln. Results from the July 15, 2008 test are 1.4 lb SAM/hr for S1 and 1.3 lb SAM/hr for S2. The results show that emissions of SAM have not increased relative to the previous test. Since the test has been performed and the results have been submitted to the facility, part 6 of Condition 136 will be deleted in this action.

Condition #136 has been re-numbered.

The basis for Condition #136, part 7, has been updated because it now contains recordkeeping to ensure that the SO2 offsets remain valid.

The description of Condition #136, part 9, has been improved. The requirement is an abatement requirement, not an operating requirement.

A prohibition against calcining coke from the Santa Maria Refinery has been imposed in Condition #136, part 19. This condition was imposed because the calciner at the Santa Maria Refinery has been shutdown to mitigate CO2 emissions from the CFEP project. The District did not believe that this mitigation should result in additional coke calcining in the Bay Area.

Table IV – A
Source-specific Applicable Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Regulation 1	**General Provisions and Definitions (~~5/1/01~~11/19/08)**		
1-107	Combination of Emissions	Y	
1-510	Area Monitoring	Y	
1-520	Continuous Emission Monitoring	Y	
1-520.8	Continuous Emission Monitoring: Required by Regulation 10 et al	Y	
1-521	Monitoring May Be Required	Y	
1-522	Continuous Emission Monitoring and Recordkeeping Procedures	Y	
1-523	Parametric Monitoring and Recordkeeping Procedures	N	
1-523.1	Parametric monitor periods of inoperation	Y	
1-523.2	Limits on periods of inoperation	Y	
1-523.3	Reports of Violations	N	
1-523.4	Records	Y	
1-523.5	Maintenance and calibration	N	
1-530	Area Monitoring Downtime	Y	
1-540	Area Monitoring Data Examination	Y	
1-542	Area Concentration Excesses	Y	
1-543	Record Maintenance for Two Years	Y	
1-544	Monthly Summary	Y	
1-545	Monitor Maintenance and Calibration	Y	
1-602	Area and Continuous Emission Monitoring Requirements	Y	
1-603	Visible Emissions	Y	
SIP Regulation 1	**General Provisions and Definitions (6/28/99)**		
1-522	Continuous Emission Monitoring and Recordkeeping Procedures	Y[1]	
1-522.7	emission limit exceedance reporting requirements	Y[1]	

Table IV – A
Source-specific Applicable Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
1-523	Parametric Monitoring and Recordkeeping Procedures	Y[1]	
1-523.3	Reports of Violations	Y[1]	
1-523.5	Maintenance and calibration	Y[1]	
BAAQMD Regulation 6, Rule 1	**Particulate Matter and Visible Emissions (12/19/90)**		
~~6-~~6-1-301	Ringelmann No.1 Limitation	~~Y~~N	
~~6-~~6-1-305	Visible Particles	~~Y~~N	
~~6-~~6-1-310	Particulate Weight Limitation	~~Y~~N	
~~6-~~6-1-310.3	Particulate Weight Limitation, Heat Transfer Operation	~~Y~~N	
~~6-~~6-1-311	General Operations	~~Y~~N	
~~6-~~6-1-401	Appearance of Emissions	~~Y~~N	
SIP Regulation 6	**Particulate Matter and Visible Emissions (9/4/98)**		
6-301	Ringelmann #1 Limitation	Y	
6-305	Visible Particles	Y	
6-310	Particulate Weight Limitation	Y	
6-310.3	Particulate Weight Limitation	Y	
6-311	General Operations	Y	
6-401	Appearance of Emissions	Y	
BAAQMD Regulation 9, Rule 1	**Inorganic Gaseous Pollutants - Sulfur Dioxide (3/15/95)**		
9-1-110	Conditional Exemption, Area Monitoring		
9-1-110.1	Monitoring, records and reporting requirements contained in Regulation 1, including Sections 1-510, 530, 540, 542, 543, and 544	Y	
9-1-110.2	Limitation on Ground Level Concentrations	Y	
9-1-301	Limitations on Ground Level Concentrations	Y	
9-1-310	Emission Limitations for Fluid Catalytic Cracking Units, Fluid Cokers, and Coke Calcining Kilns		
9-1-310.2	Emission Limitations for Coke Calcining Kilns	Y	
9-1-310.3	Compliance with 9-1-110.1 and 9-1-110.2	Y	
9-1-501	Area Monitoring Requirements	Y	
9-1-601	Sampling and Analysis of Gas Streams	Y	
9-1-603	Averaging Times	Y	
9-1-604	Ground Level Monitoring	Y	

Table IV – A
Source-specific Applicable Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Manual of Procedures, Volume V	**Continuous Emission Monitoring Policy and Procedures (1/20/82)**	Y	
40 CFR 64	**Compliance Assurance Monitoring (10/22/97)**		
64.2(a)	Applicability	Y	
64.3	Monitoring design criteria	Y	
64.3(a)	General criteria	Y	
64.3(a)(1)	Data for one or more indicators or direct measurement	Y	
64.3(a)(2)	Indicator range	Y	
64.3(a)(3)	Design of indicator ranges	Y	
64.3(b)	Performance criteria	Y	
64.3(b)(1)	Specifications for obtaining data	Y	
64.3(b)(2)	Verification procedures	Y	
64.3(b)(3)	Quality assurance and control practices	Y	
64.3(b)(4)	Specifications for frequency, procedures, and averaging periods	Y	
64.3(b)(4)(i)	Design of period over which data are obtained, etc.	Y	
64.3(b)(4)(ii)	Frequency for units that emit more than 100% of major source threshold (applies to SO2 emissions)	Y	
64.3(b)(4)(iii)	Frequency for other pollutant-specific emission units (applies to filterable particulate and PM10 emissions)	Y	
64.3(c)	Evaluation factors	Y	
64.3(d)	Special criteria for the use of continuous emission, opacity or predictive monitoring systems	Y	
64.3(d)(1)	Use of existing CEM (applies to SO2)	Y	
64.3(d)(2)(vi)	Use of CEM approved by the permitting authority	Y	
64.3(d)(3)	Monitoring system shall allow for reporting of exceedances; in absence of averaging period, develop averaging period in accordance with Section 64.3(b)(4)	Y	
64.4	Submittal requirements	Y	
64.4(a)	Submittal of monitoring that satisfies design requirements in 40 CFR 63.4	Y	
64.4(b)	Justification for the proposed monitoring	Y	
64.4(b)(1)	Presumptively acceptable monitoring approaches	Y	
64.4(b)(2)	CEMS	Y	
64.4(b)(5)?	***Presumptively acceptable monitoring approaches designed by EPA?***	Y	
64.4(c)(1)	Submittal of control device operating parameter data obtained during tests	Y	
64.4(c)(2)	Documentation of no changes to system after performance tests	Y	

Table IV – A
Source-specific Applicable Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
64.4(d)	Testing required if data not available	Y	
64.4(e)	Implementation plan	Y	
64.5(a)	Deadline for submittals for large pollutant-specific emissions units	Y	
64.5(b)	Deadline for submittals for other pollutant-specific emissions units	Y	
64.5(d)	Prior to approval, emissions unit subject to 40 CFR 70.1(a)(3)(i)(B)	Y	
64.6(a)	Approval by permitting authority	Y	
64.6(b)	Additional data collection	Y	
64.6(c)	Establishment of permit terms or conditions	Y	
64.6(d)	Installation, testing or final verification	Y	
64.7	Operation of approved monitoring	Y	
64.7(a)	Commencement of operation	Y	
64.7(b)	Proper maintenance	Y	
64.7(c)	Continued operation	Y	
64.7(d)	Response to excursions or exceedances	Y	
64.7(e)	Documentation of need for improved monitoring	Y	
64.8	Quality improvement plan	Y	
64.9	Reporting and recordkeeping requirements	Y	
64.9(a)	General reporting requirements	Y	
64.9(b)	General recordkeeping requirements	Y	
64.10	Savings provisions	Y	
BAAQMD Condition #136		Y	
Part 1	Access Ports closed during testing. (basis: BAAQMD Regulation 1, Section 401)	Y	
Part 2	Sampling ports and access shall be provided (basis: BAAQMD Regulation 1, Section 501)	Y	
Part 3a	CEMs required (basis: BAAQMD Regulation 1, Sections 521 and 522, 40 CFR 64.3)	Y	
Part 3b	~~Recordkeeping~~ Flow meters for natural gas usage (basis: BAAQMD Regulation 2-6-503)	Y	
Part 3c	Measurements of SO2 at least 4 times per hour (Basis: 40 CFR 64.3(b)(4)(ii))	Y	
Part 4	CEM standards (basis: BAAQMD Regulation 1, Section 522)	Y	
~~Part 6~~	~~Requirement for sulfuric acid mist source test (basis: Toxic Management Regulation 2, Rule 5, PSD)~~		

Table IV – A
Source-specific Applicable Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
Part ~~5~~7	Record keeping (basis: BAAQMD Regulation 1, Section 441; Regulation 2-2-303, Offsets, 40 CFR 64)	Y	
Part ~~6~~8	Baghouse maintenance requirement (basis: BAAQMD Regulations 6-1-301, 6-1-310, 6-1-311; SIP Regulations 6-301, 6-310, 6-311)~~6-301~~)	N	
Part ~~7~~9	~~Operating~~ Abatement requirement (basis: BAAQMD Regulations 6-1-301, 6-1-310, 6-310.3, and 6-1-311; SIP Regulations 6-301, 6-310, 6-310.3, and 6-311~~6, Sections 301, 310 and 311~~)	Y	
Part ~~8~~11	Pressure drop monitoring (basis: BAAQMD Regulation 2-6-409.2)	Y	
Part ~~9~~12	Pressure drop limits (basis: BAAQMD Regulations 2-6-409.2 and 2-6-501, 40 CFR 64)	Y	
Part 13~~0~~a	Visible emissions monitoring requirement (basis: BAAQMD Regulations ~~6-~~6-1-301, SIP Regulation 6-301, ~~and~~ 2-6-501; 40 CFR 64.3(b)4(iii))	Y	
Part 13~~0~~b	Annual source test requirement for S-1 and S-2 (basis: BAAQMD Regulation 2-6-501)	Y	
Part 13d	Definition of excursion for filterable particulate standards(40 CFR 64.6(c)(2))	Y	
Part 13e	Reporting of excursions (40 CFR 64.9(a)(2))	Y	
Part 13f	Submittal of Quality Improvement Plan (40 CFR 64.8)	Y	
Part 14~~1~~	Baghouse inspection (basis: BAAQMD Regulation 2-6-501)	Y	
Part 15~~2a~~	Limits on natural gas usage and calcined coke produced (basis: BAAQMD Regulation 2-1-234.3)	Y	
Part 16~~3~~	Record keeping (basis: BAAQMD Regulation 1-441)	Y	
Part 18~~4~~	Make available hourly and daily records upon request (basis: BAAQMD Regulation 1-441)	Y	
Part 19	Prohibition against calcining coke from Santa Maria Refinery (basis: Offsets, CEQA)	Y	

[1]This section has been removed from BAAQMD Regulations because it has been superseded. Nevertheless, the source must comply with this regulation until US EPA has reviewed and approved (or disapproved) the District's revision of the regulation.

The above changes have been added to the table for S-2. Following are additional changes to the requirements for S-2.

Regulation 6-1-310 has been added to the table for S-2. The calciners are subject to the general limit of 343 mg filterable particulate per dscm in Regulation 6-1-310 and the specific requirement of 343 mg filterable particulate per dscm @ 6% O2 in Regulation 6-1-310.3 because it is both a calciner and a heat transfer operation.

The facility has agreed to lower the average SO2 emissions at S-2 by 42 tons per year to provide offsets for the CFEP project, so an annual SO2 limit has been imposed in Condition #136, part 5.

The facility has agreed to lower the average PM10 emissions at S-2 by 8 tons per year to provide CEQA mitigation for the CFEP project, so an annual PM10 limit has been imposed in Condition #136, part 10. This limit is not federally enforceable, since it has been imposed pursuant to a state program. An annual testing requirement has been imposed in part 13c and a recordkeeping requirement has been imposed in part 17.

Table IV - B
Source-specific Applicable Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Regulation 1	**General Provisions and Definitions (11/19/08~~5/2/01~~)**		
1-107	Combination of Emissions	Y	
1-510	Area Monitoring	Y	
1-520	Continuous Emission Monitoring	Y	
1-520.8	Continuous Emission Monitoring: Required by Regulation 10 et al	Y	
1-521	Monitoring May Be Required	Y	
1-522	Continuous Emission Monitoring and Recordkeeping Procedures	Y	
1-523	Parametric Monitoring and Recordkeeping Procedures	N	
1-523.1	Parametric monitor periods of inoperation	Y	
1-523.2	Limits on periods of inoperation	Y	
1-523.3	Reports of Violations	N	
1-523.4	Records	Y	
1-523.5	Maintenance and calibration	N	
1-530	Area Monitoring Downtime	Y	
1-540	Area Monitoring Data Examination	Y	
1-542	Area Concentration Excesses	Y	
1-543	Record Maintenance for Two Years	Y	
1-544	Monthly Summary	Y	
1-545	Monitor Maintenance and Calibration	Y	
1-602	Area and Continuous Emission Monitoring Requirements	Y	
1-603	Visible Emissions	Y	
SIP Regulation 1	**General Provisions and Definitions (6/28/99)**		
1-522	Continuous Emission Monitoring and Recordkeeping Procedures	Y[1]	
1-522.7	emission limit exceedance reporting requirements	Y[1]	

Table IV - B
Source-specific Applicable Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
1-523	Parametric Monitoring and Recordkeeping Procedures	Y[1]	
1-523.3	Reports of Violations	Y[1]	
1-523.5	Maintenance and calibration	Y[1]	
BAAQMD Regulation 6, Rule 1	**Particulate Matter and Visible Emissions (12/19/90)**		
~~6-~~6-1-301	Ringelmann No.1 Limitation	Y	
~~6-~~6-1-305	Visible Particles	Y	
6-1-310	Particulate Weight Limitation	Y	
~~6-~~6-1-310.3	Particulate Weight Limitation, Heat Transfer Operation	Y	
~~6-~~6-1-311	General Operations	Y	
~~6-~~6-1-401	Appearance of Emissions	Y	
SIP Regulation 6	**Particulate Matter and Visible Emissions (9/4/98)**		
6-301	Ringelmann #1 Limitation	Y	
6-305	Visible Particles	Y	
6-310	Particulate Weight Limitation	Y	
6-310.3	Particulate Weight Limitation	Y	
6-311	General Operations	Y	
6-401	Appearance of Emissions	Y	
BAAQMD Regulation 9, Rule 1	**Inorganic Gaseous Pollutants - Sulfur Dioxide (3/15/95)**		
9-1-110	Conditional Exemption, Area Monitoring		
9-1-110.1	Monitoring, records and reporting requirements contained in Regulation 1, including Sections 1-510, 530, 540, 542, 543, and 544	Y	
9-1-110.2	Limitation on Ground Level Concentrations	Y	
9-1-301	Limitations on Ground Level Concentrations	Y	
9-1-310	Emission Limitations for Fluid Catalytic Cracking Units, Fluid Cokers, and Coke Calcining Kilns		
9-1-310.2	Emission Limitations for Coke Calcining Kilns	Y	
9-1-310.3	Compliance with 9-1-110.1 and 9-1-110.2	Y	
9-1-501	Area Monitoring Requirements	Y	
9-1-601	Sampling and Analysis of Gas Streams	Y	
9-1-603	Averaging Times	Y	
9-1-604	Ground Level Monitoring	Y	

Table IV - B
Source-specific Applicable Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Manual of Procedures, Volume V	**Continuous Emission Monitoring Policy and Procedures (1/20/82)**	Y	
40 CFR 64	**Compliance Assurance Monitoring (10/22/97)**		
64.2(a)	Applicability	Y	
64.3	Monitoring design criteria	Y	
64.3(a)	General criteria	Y	
64.3(a)(1)	Data for one or more indicators or direct measurement	Y	
64.3(a)(2)	Indicator range	Y	
64.3(a)(3)	Design of indicator ranges	Y	
64.3(b)	Performance criteria	Y	
64.3(b)(1)	Specifications for obtaining data	Y	
64.3(b)(2)	Verification procedures	Y	
64.3(b)(3)	Quality assurance and control practices	Y	
64.3(b)(4)	Specifications for frequency, procedures, and averaging periods	Y	
64.3(b)(4)(i)	Design of period over which data are obtained, etc.	Y	
64.3(b)(4)(ii)	Frequency for units that emit more than 100% of major source threshold (applies to SO2 emissions)	Y	
64.3(b)(4)(iii)	Frequency for other pollutant-specific emission units (applies to filterable particulate and PM10 emissions)	Y	
64.3(c)	Evaluation factors	Y	
64.3(d)	Special criteria for the use of continuous emission, opacity or predictive monitoring systems	Y	
64.3(d)(1)	Use of existing CEM (applies to SO2)	Y	
64.3(d)(2)(vi)	Use of CEM approved by the permitting authority	Y	
64.3(d)(3)	Monitoring system shall allow for reporting of exceedances; in absence of averaging period, develop averaging period in accordance with Section 64.3(b)(4)	Y	
64.4	Submittal requirements	Y	
64.4(a)	Submittal of monitoring that satisfies design requirements in 40 CFR 63.4	Y	
64.4(b)	Justification for the proposed monitoring	Y	
64.4(b)(1)	Presumptively acceptable monitoring approaches	Y	
64.4(b)(2)	CEMS	Y	
64.4(b)(5)?	***Presumptively acceptable monitoring approaches designed by EPA?***	Y	

Table IV - B
Source-specific Applicable Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
64.4(c)(1)	Submittal of control device operating parameter data obtained during tests	Y	
64.4(c)(2)	Documentation of no changes to system after performance tests	Y	
64.4(d)	Testing required if data not available	Y	
64.4(e)	Implementation plan	Y	
64.5(a)	Deadline for submittals for large pollutant-specific emissions units	Y	
64.5(b)	Deadline for submittals for other pollutant-specific emissions units	Y	
64.5(d)	Prior to approval, emissions unit subject to 40 CFR 70.1(a)(3)(i)(B)	Y	
64.6(a)	Approval by permitting authority	Y	
64.6(b)	Additional data collection	Y	
64.6(c)	Establishment of permit terms or conditions	Y	
64.6(d)	Installation, testing or final verification	Y	
64.7	Operation of approved monitoring	Y	
64.7(a)	Commencement of operation	Y	
64.7(b)	Proper maintenance	Y	
64.7(c)	Continued operation	Y	
64.7(d)	Response to excursions or exceedances	Y	
64.7(e)	Documentation of need for improved monitoring	Y	
64.8	Quality improvement plan	Y	
64.9	Reporting and recordkeeping requirements	Y	
64.9(a)	General reporting requirements	Y	
64.9(b)	General recordkeeping requirements	Y	
64.10	Savings provisions	Y	
BAAQMD Condition #136		Y	
Part 1	Access Ports closed during testing. (basis: BAAQMD Regulation 1, Section 401~~104~~)	Y	
Part 2	Sampling ports and access shall be provided (basis: BAAQMD Regulation 1, Section 501)	Y	
Part 3a	CEMs required (basis: BAAQMD Regulation 1, Sections 521 and 522, 40 CFR 64.3)	Y	
Part 3b	~~Recordkeeping~~ Flow meters for natural gas usage (basis: BAAQMD Regulation 2-6-503)	Y	
Part 3c	Measurements of SO2 at least 4 times per hour (Basis: 40 CFR 64.3(b)(4)(ii))	Y	

Table IV - B
Source-specific Applicable Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
Part 4	CEM standards (basis: BAAQMD Regulation 1, Sections 522)	Y	
Part 5	Annual SO2 Limit (Basis: Regulation 2-2-303, Offsets)	~~Y~~	
~~Part 6~~	~~Requirement for sulfuric acid mist source test (basis: Toxic Management Regulation 2, Rule 5, PSD)~~	~~Y~~	
Part ~~5~~7	Record keeping (basis: BAAQMD Regulations 1~~-, Section~~ 441; 2-2-303; Offsets, 40 CFR 64)	Y	
Part ~~6~~8	Baghouse maintenance requirement (basis: BAAQMD Regulations 6-1-301, 6-1-310, 6-1-311; SIP Regulations 6-301, 6-310, 6-311~~6-301~~)	~~N~~Y	
Part ~~7~~9	~~Operating~~ Abatement requirement (basis: BAAQMD Regulations ~~6, Sections~~ 6-1-301, 6-1-310, 6-310.3, and 6-1-311; SIP Regulations 6-301, 6-310, 6-310.3, and 6-311)	Y	
Part 10	Annual PM10 limit (basis: CEQA)	N	
Part ~~8~~11	Pressure drop monitoring (basis: BAAQMD Regulation 2-6-409.2)	Y	
Part ~~9~~12	Pressure drop Limits (basis: BAAQMD Regulations 2-6-409.2 and 2-6-501, cumulative increase, 40 CFR 64)	Y	
Part 13~~0~~a	Visible emissions monitoring requirement (basis: BAAQMD Regulations 6-1-301. 2-6-501, 40 CFR 64.3(b)4(iii))	Y	
Part 13~~0~~b	Annual source test requirement for S-1 and S-2 (basis: BAAQMD Regulation 2-6-501)	Y	
Part 13c	Annual source test requirement for S-2 (basis: CEQA)	N	
Part 13d	Definition of excursion for filterable particulate standards(40 CFR 64.6(c)(2))	Y	
Part 13e	Reporting of excursions (40 CFR 64.9(a)(2))	Y	
Part 13f	Submittal of Quality Improvement Plan (40 CFR 64.8)	Y	
Part 14~~1~~	Baghouse inspection (basis: BAAQMD Regulation 2-6-501)	Y	
Part 15~~12b~~	Limits on natural gas usage and calcined coke produced (basis: BAAQMD Regulation 2-1-234.3)	Y	
Part 16~~3~~	Record keeping (basis: BAAQMD Regulation 1-441)	Y	
Part 17	Recordkeeping for PM10 (basis: CEQA)	N	
Part 18~~4~~	Make available hourly and daily records upon request (basis: BAAQMD Regulation 1-441)	Y	
Part 19	Prohibition against calcining coke from Santa Maria Refinery (basis: Offsets, CEQA)	Y	
BAAQMD Condition #3752			
Part 1	Natural gas firing only (basis: cumulative increase)	Y	

Table IV - B
Source-specific Applicable Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
Part 2	Annual fuel usage limitation (basis: cumulative increase)	Y	
Part 3	Record keeping (basis: BAAQMD Regulation 1, Section 441 and cumulative increase)	Y	
BAAQMD Condition 22970			
Part B.1	Offset report (2-1-403, 2-2-410)	Y	

[1]This section has been removed from BAAQMD Regulations because it has been superseded. Nevertheless, the source must comply with this regulation until US EPA has reviewed and approved (or disapproved) the District's revision of the regulation.

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."

Since the District has not determined that the facility is out of compliance with an applicable requirement, the schedule of compliance for this permit contains only sections 2-6-409.10.1 and 2-6-409.10.2.

VI. Permit Conditions

The Major Facility Review permit contains conditions that are derived from previously issued District Authorities to Construct (A/C) or Permits to Operate (P/O). Permit conditions may also be imposed or revised as part of the annual review of the facility by the District pursuant to California Health and Safety Code (H&SC) § 42301(e), through a variance pursuant to H&SC §

42350 et seq., an order of abatement pursuant to H&SC § 42450 et seq., or as an administrative revision initiated by District staff. After issuance of the Title V permit, permit conditions will be revised using the procedures in Regulation 2, Rule 6, Major Facility Review.

When necessary to meet Title V requirements, additional monitoring, recordkeeping, or reporting has been added to the permit.

Each permit condition is identified with a unique numerical identifier, up to five digits.

All changes to existing permit conditions that are proposed in this action are clearly shown in "strike-out/underline" format in the proposed permit. When the permit is issued, all 'strike-out" language will be deleted and all "underline" language will be retained, subject to consideration of comments received.

Changes to permit:
BAAQMD Regulation 6, Particulate Matter, has been changed to Regulation 6, Particulate Matter, Rule 1, General Requirements. The citations of the rule will be changed throughout the permit.

The facility has agreed to lower the average SO2 emissions at S-2 by 42 tons per year to provide offsets for the CFEP project, so an annual SO2 limit has been imposed in Condition #136, part 5. SO2 is monitored by a CEM pursuant to part 3a. A recordkeeping requirement has been imposed in part 7 to ensure compliance.

ConocoPhillips agreed to source test the calciners to determine whether there is an increase in sulfuric acid mist due to heat recovery. The requirement was added in Condition #136, part 6. The purpose was to resolve speculation that sulfuric acid mist could have increased by more than 7 tons per year in 1982 when the heat recovery system was installed. The source testing was completed by July 15, 2008. The only existing test prior to installation of the heat recovery system had a result of 6.24 lb SAM/hr from S2, Kiln. Results from the July 15, 2008 test are 1.4 lb SAM/hr for S1 and 1.3 lb SAM/hr for S2. The results show that emissions of SAM have not increased relative to the previous test. Since the test has been performed and the results have been submitted to the facility, part 6 of Condition 136 will be deleted in this action.

The facility has agreed to lower the average PM10 emissions at S-2 by 8 tons per year to provide CEQA mitigation for the CFEP project, so an annual PM10 limit has been imposed in Condition #136, part 10. This limit is not federally enforceable, since it has been imposed pursuant to a state program. An annual testing requirement has been imposed in part 13c and a recordkeeping requirement has been imposed in part 17.

Condition #136, part 11, required that the facility install a manometer or other District approved differential pressure measuring device at each baghouse and determine the minimum pressure drop at which the baghouse operates properly. ConocoPhillips submitted the parameters on January 3, 2003. In this action, the parts 11 and 12 will be amended to show that the manometer has been installed and is being used for monitoring. ~~The proper pressure drop range will be added to the permit.~~The January 3, 2003 letter proposed pressure drops for these baghouses between 4.5 and 7.0 inches of water gauge. Since the letter was submitted, the mode of operation has changed. The baghouses are cleaned at least once per shift, which has changed the pressure drop range to 1.0 to 10.0 inches gauge. Also, each baghouse has 8 modules that are isolated from flue gas flow during cleaning and maintenance. The pressure drop will be allowed to drop to zero in those modules during those periods.

A prohibition against calcining coke from the Santa Maria Refinery has been imposed in Condition #136, part 19. This condition was imposed because the calciner at the Santa Maria Refinery has been shutdown to mitigate CO2 emissions from the CFEP project. The District did not believe that this mitigation should result in additional coke calcining in the Bay Area.

Condition #136
For: **S-1 K-1 Coke Calcine Kiln/Cooler**
S-2 K-2 Coke Calcine Kiln/Cooler

Any condition that is preceded by an asterisk is not federally enforceable.

1.All pyroscrubber access ports shall be closed during source tests conducted to determine compliance with District regulations and/or permit conditions. (Basis: BAAQMD Regulation 1-401)

2. APCO approved sampling ports and access platforms shall be provided downstream of each baghouse. (Basis: BAAQMD Regulation 1-501)

3a. The permit holder shall operate and maintain a continuous emission monitoring system to quantify:

~~a~~1. the concentration of sulfur dioxide inside each kiln~~'~~’s exhaust stack, and
~~b~~2. the flowrate of combustion products from each exhaust stack, and
~~c~~3. the mass emission rate of sulfur dioxide from each exhaust stack into the atmosphere.
(Basis: BAAQMD Regulations 1-521 and 522; 40 CFR 64.3)

3b. The permit holder shall use gas flow meters to record the flow of natural gas to the kilns and pyroscrubbers. (Basis: BAAQMD Regulation 2-6-503)

3c. The permit holder shall obtain the measurements required by part 3a at least 4 times in every clock hour at all times that the S-1 and/or S-2 are operating and obtain an hourly measurement of sulfur dioxide concentration and sulfur dioxide mass emissions, except for periods of monitoring malfunctions, associated repairs, and required quality assurance or control activities as allowed by 40 CFR 64.7(c). (Basis: 40 CFR 64.3(b)(4)(ii))

3d, The permit holder shall monitor the bypass stack by noting decreases in the concentration and flow at the SO2 CEM at the main stack. Bypassing of the control devices is considered to be a violation. (Basis: 40 CFR 64.3(a))

4. The continuous emission monitoring system shall meet the requirements of the Manual of Procedures, Volume V, Continuous Emission Monitoring Policy and Procedures (Basis: BAAQMD Regulation 1-522)

5. The owner/operator shall ensure that SO_2 emissions from S-2 do not exceed 749.32 tons in any consecutive 12-month period. (Basis: BAAQMD Regulation 2-2-303; Offsets)

6. ~~Within one year from the issuance of the Authority to Construct number 15328, the owner/operator shall conduct District-approved source tests to determine hourly sulfuric acid mist emissions from S-1 and S-2, Kilns. The owner/operator shall submit protocols for all source test procedures to the District's Source Test Section at least three weeks prior to conducting any tests. The owner/operator shall notify the District's Source Test Section, in writing, of the projected test dates at least 7 days prior to testing. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test. (basis: Toxic Management Regulation 2, Rule 5, PSD)~~Deleted Application 17331.

7~~5~~. In order to demonstrate compliance with the parts 3, ~~and~~ 4, and 5 of this condition, the following records shall be maintained in a District approved log. These records shall be kept on site and made available for District inspection for a period of 5 years from the date on which a record is made:

a. the concentration of sulfur dioxide inside each kiln's exhaust stack, as prescribed in part 3 of this condition.
b. the mass emission rate of sulfur dioxide from each exhaust stack into the atmosphere, as prescribed in part 3 of this condition.
c. Amount of natural gas burned on a monthly basis (therms/month).
d. Continuous emission monitoring measurements for sulfur dioxide.
e. Date, time, and duration of any startup, shutdown, or malfunction of any kiln, emission control equipment, or emission monitoring equipment.
f. Results of performance testing, evaluations, calibrations, checks, adjustments, and maintenance of any CEMs.
g. Hourly sulfur dioxide concentration and emission rate
h. Annual sulfur dioxide emission rate in tons at S-2 to ensure compliance with part 5 of this condition.
i~~h~~. Hourly flow rate of combustion products
(basis: BAAQMD Regulations 1-441, ~~Reg.~~ 2-2-303;~~,~~ Offsets; 40 CFR 64)

~~*6~~8. The permit holder shall keep the Baghouses, A-10 and A-11 in good operating condition. (basis: BAAQMD Regulations ~~6~~ 6-1-301, 6-1-310, 6-1-310.3, 6-1-311; SIP Regulations 6-301, 6-310, 6-310.3, 6-311)

9~~7~~. All particulate matter emissions from S-1 and S-2 shall be routed to the baghouses A-10 and A-11, respectively. (basis: BAAQMD Regulations ~~6~~ 6-1-301, ~~6~~ 6-1-310, 6-1-310.3, ~~6~~ 6-1-311; SIP Regulations 6-301, 6-310, 6-310.3, 6-311)

*****10. The owner/operator shall ensure that PM_{10} emissions from S-2 do not exceed 29.40 tons in any consecutive 12-month period. The emissions shall be calculated assuming that S-2 operates normally for 21.5 hours per day and soot blowing and/or baghouse cleaning occurs for 2.5 hours per day. Normal operating emissions shall be estimated using the emissions from the most recent Condition 136 Part 12b source test. Soot blowing/baghouse cleaning emissions shall be based on an emission rate of 1.412 lb PM10 per ton of coke processed. (Basis: CEQA)

11~~8~~. ~~Within 3 months of final issuance of the Major Facility Review permit,~~ The permit holder shall ~~install~~ maintain ~~a~~ District approved manometers or other District approved devices which measure~~s~~ the pressure drop across each module of each baghouse, A-10 and A-11. The pressure drop shall be maintained between ~~4.5 and 7.0~~ 1.0 and 10.0 inches of water gauge unless the module is isolated from flow during cleaning, bag replacement or other maintenance. During these times, a pressure drop below 1.0 inch of water gauge is allowed. If the pressure drop of a module is below 1.0 inch of water gauge and it is not isolated from flow, the permit holder shall record the pressure drop in a log and take corrective action. ~~Within 6 months of final issuance of the Major Facility Review permit, the permit holder shall determine the proper pressure drop range for each baghouse. These ranges shall be submitted to the Permits Division of the District for inclusion in the permit as an administrative permit amendment.~~ (basis: BAAQMD Regulation 2-6-409.2)

12~~9~~. ~~After installation of the manometer or devices,~~ The manometer or device shall be operational at all times that the above sources are operated. The pressure drop across the baghouses shall be recorded once a week to ascertain that the pressure drops are in the normal operating range, and the baghouses are in good operating condition. The records shall be kept on site for at least five years from the date of data entry and be made available to the District staff for inspection. (basis: BAAQMD Regulations~~-~~ 2-6-409.2 and 2-6-501)

13~~10~~. a. Visible particulate emissions from S-1 and S-2 shall be monitored ~~quarterly~~ on a daily basis using the EPA Method 22~~District method (Manual of Procedures, Volume I, Evaluation of Visible Emissions)~~ and shall be retained on site for a minimum period of five years from the date of data entry and be made available to the District staff for inspection.
(basis: BAAQMD Regulations ~~6-~~6-1-301, ~~Regulation~~ 2-6-501, 40 CFR 64.3(b)4(iii))

b. The owner/operator of S1 and S2 shall conduct an annual District-approved source test at each furnace in order to demonstrate compliance with Regulation ~~6-~~6-1-310, ~~6-~~6-1-310.3 and ~~6-~~6-1-311. The results of these tests shall be kept on site for at least five years from the date of the test and be made available to District staff upon request.
(basis: BAAQMD Regulation 2-6-501)

*c. The owner/operator of ~~S1 and~~ S2 shall conduct an annual District-approved source test at S2 in order to demonstrate compliance with part 10 of this condition. The results of these tests shall be kept on site for at least five years from the date of the test and be made available to District staff upon request.
(basis: CEQA)

d. The owner/operator shall determine that a reading of any visible emissions during the daily visible particulate monitoring performed pursuant to part 13a of this condition is an excursion as defined by 40 CFR 64.1 for the following standards:

i. BAAQMD Regulation 6-1-310
ii. BAAQMD Regulation 6-1-310.3
iii. BAAQMD Regulation 6-1-311
iv. SIP Regulation 6-310
v. SIP Regulation 6-310.3
vi. SIP Regulation 6-311

(40 CFR 64.6(c)(2))

e. The owner/operator shall report any excursions determined in accordance with BAAQMD Condition 136, parts 13a and 13d on the semi-annual monitoring report required by Standard Condition I.F of the Major Facility Review permit. (40 CFR 64.9(a)(2))

f. The owner/operator shall submit a Quality Improvement Plan in accordance with 40 CFR 64.8 if the owner/operator determines that there have been more than 9 excursions (5% of daily readings) in any monitoring report period. (40 CFR 64.8)

14~~11~~. Each baghouse shall be inspected on an annual basis to ensure proper operation. Records of each annual inspection shall be kept on site for at least five years from the date of data entry and be made available to the District staff for inspection.
(basis: BAAQMD Regulation 2-6-501)

15~~12~~. Natural gas usage and calcined petroleum coke produced shall not exceed the following in any consecutive 12-month period:

a. For S-1:
Natural gas usage at the S-1 burner: 5.25 million therms
Natural gas usage at the A-1 burner: 2.6 million therms
Calcined petroleum coke produced: 262,800 tons

b. For S-2:
Natural gas usage at the S1 burner: 5.00 million therms
Natural gas usage at the A1 burner: 2.6 million therms
Calcined petroleum coke produced: 262,800 tons
(basis: BAAQMD Regulation 2-1-234.3)

16~~13~~. The permit holder shall maintain the following records for each limit listed in part 15 ~~12~~:

a. Monthly natural gas usage per burner and per source
b. Monthly calcined petroleum coke produced per source
c. Total natural gas usage per burner and per source for the preceding 12 months
d. Total calcined petroleum coke produced per source for the preceding 12 months
(basis: BAAQMD Regulation 1-441~~, CEQA~~)

*17. The permit holder shall maintain records of the annual PM10 emission rate in tons at S-2 to ensure compliance with part 10 of this condition. (basis: CEQA)

18~~14~~. The permit holder shall make available to the APCO, upon request, any records relating to hourly or daily fuel usage or coke throughput. (basis: BAAQMD Regulation 1-441)

19. The ConocoPhillips Carbon Plant shall not calcine any coke from the Santa Maria refinery. [Offsets, CEQA]

The purpose of Condition 22970 is to ensure that the CFEP project does not exceed its proposed annual limits and to ensure that the proposed offsets are provided. S-2, Coke Calciner, is subject to part B.1. The changes to part A are discussed in the Statement of Basis for Application 13427 for the ConocoPhillips refinery.

CONDITION 22970
A. CFEP Project Mass Emission Limits
1. Following are the sources that are subject to Condition 22970, parts A2, A4, and A.5:
S45, Heater (U246 B-801 A/B)
S434, U246 High Pressure Reactor Train (Cracking)
S1010~~04~~, U235 Sulfur Recovery Unit
[Cumulative increase, PSD]

2. The owner/operator shall ensure that the annual emissions of the above sources do not exceed the following annual emission limits, including startup, shutdown, malfunction, and upset emissions.
   a. NOx 13.5 tpy [Cumulative increase]
   b. SO2 34.4 tpy [Cumulative increase, PSD]
   c. PM10 2.5 tpy [Cumulative increase]
   d. POC 1.9 tpy [Cumulative increase]
   e. CO 40.72 tpy [Cumulative increase]
   f. Sulfuric acid mist 6.01 tpy [PSD]
   g. Ammonia 6.35 tpy [BAAQMD Regulation 2, Rule 5]

3. The owner/operator shall ensure that the daily emissions of the CFEP, including source S2 at Facility B7419, do not exceed the following daily emission limit, including startup, shutdown, malfunction, and upset emissions.
   a. Sulfuric acid mist 38 lb/day [PSD]

4. The owner/operator shall determine whether the emissions are below the allowable emissions in Part A.2, as shown below. The owner/operator shall calculate and report the emissions of NOX, SO2, PM10, POC, CO, and sulfuric acid mist on an annual basis in the following manner.
   a. For Source S45, Heater
      i. Use the mass emissions data generated by the NOx CEM at S45.
      ii. Use the emissions rates determined by semi-annual source tests for CO at S45.
      iii. Use the emissions rates determined by initial source test for POC, PM10, ammonia, and sulfuric acid mist at S45.
      iv. Use the sulfur analysis of fuel required by Condition 22862, part 11 at S45.
      [Cumulative increase, PSD, BAAQMD Regulation 2, Rule 5]
   b. For Source S1010~~04~~, Sulfur Recovery Unit
      i. Use the mass emissions data generated by the SO2 and CO CEMs at S1010~~04~~.
      ii. Use the emissions rates determined by annual source tests for NOx, sulfuric acid mist, and ammonia, at S1010~~04~~.
      iii. Use the emissions rates determined by initial source test for POC and PM10 at S1010.
      [Cumulative increase, PSD, BAAQMD Regulation 2, Rule 5]
   c. For the refinery flare S296
      i. Calculate any emissions caused by venting the contents of any part of the sulfur recovery unit including S1010~~04~~, A48, and A424 to the refinery flare.
      ii. Calculate any emissions caused by venting the contents of any part of S434, to ~~the~~ a refinery flare.
      iii. The owner/operator shall calculate any emissions caused by venting the feed to Facility B7419, sources S1 or S2 to the refinery flare.
      [Cumulative increase, PSD, BAAQMD Regulation 2, Rule 5]

5. If the annual emissions, as determined in part 4~~3~~, are above the allowable emissions in part A.2~~1~~, the owner/operator shall supply additional offsets, where applicable, and perform additional analysis for PSD, if necessary. The results of the analysis shall be submitted to the Director of Compliance and Enforcement on an annual basis on the anniversary of the startup of S1010~~04~~ or S434, whichever is earlier. [Offset, PSD]

~~6. The annual emissions of the following sources shall not exceed 16.3 tons PM10/yr: S45, S434, and S1004 at Facility A0016, and S2 and S3 at Facility B7419. If the emissions~~

~~exceed 16.3 tons in any consecutive 12-month period, the owners/operators of Facilities A0016 and B7419 shall provide contemporaneous offsets of PM10 that comply with BAAQMD Regulations 2-2-201 and 2-2-605. [1-104, 2-2-304]~~

6. The annual emissions of the following sources shall not exceed 16.3 tons PM10/yr: S45, S434, and S1010 at Facility A0016, and S2 and S3 at Facility B7419. If the emissions exceed 16.3 tons per year, the owners/operators of Facilities A0016 and B7419 shall provide contemporaneous offsets of PM10 that comply with BAAQMD Regulations 2-2-201 and 2-2-605. The owners/operators shall use the following data to calculate the annual PM10 emissions:
   a. The emissions rate of PM10 determined by the initial source tests at S45 and S1010 at Facility A0016
   b. The emissions rate of PM10 determined by the initial source test at S2 at Facility B7419
   c. The emissions rate of PM10 calculated for venting the contents of any part of S434 to a refinery flare
   d. The emissions rate of PM10 calculated for venting the contents of any part of S1010, A48, and A424 to a refinery flare
   e, The emissions rate of PM10 calculated for operation of S3, Hydrogen Plant Flare, at Facility B7419
   The results of the analysis shall be submitted to the Director of Compliance and Enforcement on an annual basis on the anniversary of the startup of S1010 or S434 at Facility A0016 or S2 at Facility B7419, whichever is earlier.
   [1-104, 2-2-304]

B. Contemporaneous Offset Conditions

1. The owner/operator shall submit an offset report to the Director of Compliance and Enforcement and the Manager of Permit Evaluation at the end of every quarter after the initial date of startup of any of the new CFEP sources below. The report shall contain the detail of banked and contemporaneous offsets provided for each source to show compliance with the provision in BAAQMD Regulation 2-2-410 that offsets must commence no later than the initial operation of a new source or within 90 days after initial operation of a modified source. After all of the offsets required are provided, the owner/operator may submit the final report, even if all of the sources in the CFEP project are not built.

   New CFEP Sources
   Plant B7419, S1, Hydrogen Plant
   Plant B7419, S2, Hydrogen Plant Furnace
   Plant B7419, S3, Hydrogen Plant Flare
   Plant A0016, S45, Heater
   Plant A0016, S434, U246 High Pressure Reactor Train
   Plant A0016, S1010~~04~~, U235 Sulfur Recovery Unit

   Contemporaneous Offset Sources
   Plant A0016, S1007, Dissolved Air Flotation Unit (DAF)
   Plant A0016, S8, Unit 240 B-1
   Plant A0016, S352 – S357, Steam Power Plant Gas Turbines and HRSGs
   Plant A0022, S2, Kiln K-2
   [2-1-403, 2-2-410]

VII. Applicable Limits and Compliance Monitoring Requirements

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

Changes to permit:

BAAQMD Regulation 6, Particulate Matter, has been changed to Regulation 6, Particulate Matter, Rule 1, General Requirements. The citations of the rule will be changed for the sources affected by this action and during the Major Facility Review permit renewal for the remaining sources.

Condition #136 has been re-numbered.

Condition #136, part 11, required that the facility install a manometer or other District approved differential pressure measuring device at each baghouse and determine the minimum pressure drop at which the baghouse operates properly. ConocoPhillips submitted the parameters on January 3, 2003. In this action, the parameters will be added to the permit.

Tables VII-A and VII-B state that the calciner throughput is monitored on a daily basis, but Condition #136, part 16, states that the throughput is monitored on a monthly and annual basis. Since the permit condition governs, the monitoring frequency in column "Monitoring Frequency" has been changed to monthly and annual.

BAAQMD Regulation 9-1-310.2 has two limits: a concentration limit of 400 ppm SO2 and a mass emission limit of 113 kg/hr. At any given time, the most restrictive applies, so the limits have been combined. In the rule, the concentration limit has no averaging time. Since the sources are subject to 40 CFR 64 and Section 64.3(b)(4)(ii) requires an hourly averaging time for sources that emit more than the major source threshold after control, an hourly averaging time has been added to the concentration limit.

Condition #136, parts 15a and 15b state that the coke throughput for each calciner is 262,800 tons per any consecutive 12-month period, but Tables VII-A and VII-B state that the throughputs for S-1 and S-2 are 171,000 and 182,500 tons per year, respectively. Since the permit condition governs, the throughput has been corrected to 262,800 tons per any consecutive 12-month period each.

The annual SO2 and PM10 limits have been added to Table VII-B for S-2.

As discussed extensively in Section C.IV and C.VI of this statement of basis, S-1 and S-2, Kilns are subject to 40 CFR 64, Compliance Assurance Monitoring (CAM). Therefore, the frequency of visible emissions monitoring has been increased to daily.

Visible emissions monitoring is a direct measurement for BAAQMD Regulation 6-1-301 and SIP Regulation 6-301, Ringelmann #1 Limitation. It will also be used as an "indicator of emission control" as required by 40 CFR 64.3(a)(1) for BAAQMD Regulations 6-1-310 and 6-1-311 and SIP Regulations 6-310 and 6-311. So, visible emissions monitoring will be used in addition to the existing monitoring for these standards.

As explained in Section C.VI, Condition #136, part 11, required that the facility install a manometer or other District approved differential pressure measuring device at each baghouse and determine the minimum pressure drop at which the baghouse operates properly. ConocoPhillips submitted the parameters on January 3, 2003. In this action, the parts 11 and 12 will be amended to show that the manometer has been installed and is being used for monitoring. The January 3, 2003 letter proposed pressure drops for these baghouses between 4.5 and 7.0 inches of water gauge. Since the letter was submitted, the mode of operation has changed. The baghouses are cleaned at least once per shift, which has changed the pressure drop range to 1.0 to 10.0 inches gauge. Also, each baghouse has 8 modules that are isolated from flue gas flow during cleaning and maintenance. The pressure drop will be allowed to drop to zero in those modules during those periods.

Table VII – A
Applicable Limits and Compliance Monitoring Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
Opacity	BAAQMD ~~6-~~6-1-301	~~Y~~N		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, part 13~~0~~a	P/~~Q~~D	Visible emission monitoring
	SIP 6-301	Y		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	BAAQMD ~~6-~~6-1-301	~~Y~~N		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, parts ~~8 and 9~~11 and 12	P/W	Pressure drop monitoring
	SIP 6-301	Y		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring
	BAAQMD ~~6-~~6-1-301	~~Y~~N		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection
	SIP 6-301	Y		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection

Table VII – A
Applicable Limits and Compliance Monitoring Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
FP	BAAQMD 6-1-310	N		0.15 gr/dscf	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
FP	BAAQMD ~~6~~ 6-1-310	~~Y~~N		0.15 gr/dscf	BAAQMD Cond. #136, parts ~~8 and 9~~11 and 12	P/W	Pressure drop monitoring
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring
FP	BAAQMD ~~6~~ 6-1-310	~~Y~~N		0.15 gr/dscf	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection
	BAAQMD ~~6~~ 6-1-310	~~Y~~N		0.15 gr/dscf	BAAQMD Cond. #136, part 13~~0~~b	P/A	Source test
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, part 13b	P/A	Source test
	BAAQMD 6-1-310.3	N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	BAAQMD ~~6~~ 6-1-310.3	~~Y~~N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, parts ~~8 and 9~~11 and 12	P/W	Pressure drop monitoring

Table VII – A
Applicable Limits and Compliance Monitoring Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring
FP	BAAQMD ~~6~~ 6-1-310.3	~~Y~~N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection
	BAAQMD ~~6~~ 6-1-310.3	~~Y~~N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13~~0~~b	P/A	Source test
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13b	P/A	Source test
	BAAQMD 6-1-311	N		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	SIP 6-311	Y		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	BAAQMD ~~6~~ 6-1-311	~~Y~~N		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, parts ~~8 and~~ ~~9~~11 and 12	P/W	Pressure drop monitoring
	SIP 6-311	Y		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring
	BAAQMD ~~6~~ 6-1-311	~~Y~~N		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection

Table VII – A
Applicable Limits and Compliance Monitoring Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
	SIP 6-311	Y		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection
	BAAQMD ~~6-~~6-1-311	~~Y~~N		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13~~0~~b	P/A	Source test
	SIP 6-311	Y		$4.10P^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13b	P/A	Source test
	BAAQMD Cond. #136, parts 11 and 12	Y		Pressure drop at the baghouse shall be maintained between 1.0 and 10.0 inches of water gauge except during cleaning and maintenance	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring
SO2	BAAQMD Regulation 9-1-301	Y		ground level concentrations shall not exceed: 0.5 ppm for 3 consecutive minutes AND 0.25 ppm averaged over 60 consecutive minutes AND 0.05 ppm averaged over 24 hours	BAAQMD Regulation 9-1-501	C	CEM
	9-1-310.2	Y		400 ppm by volume, averaged over one hour or 113 kg per hour, whichever is most restrictive	BAAQMD Cond. #136, part 3	C	CEM
	~~9-1-310.2~~	~~Y~~		~~113 kg per hour~~	~~BAAQMD Cond. #136, part 3~~	~~C~~	~~CEM~~
Calcined coke through-put	BAAQMD Cond. #136, part ~~12~~ 15a.	Y		~~171,000~~262,800 tons/yr	BAAQMD Cond. #136, part 16~~3~~ d	P/~~D~~M/A	Record keeping

Table VII – A
Applicable Limits and Compliance Monitoring Requirements
S-1 K-1 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
Fuel usage	BAAQMD Cond. #136, part ~~12~~ 15a.	Y		5.25 million therms/yr for S-1 and 2.6 million therms/yr for A-1	BAAQMD Cond. #136, parts 1~~6~~~~3~~a and c	P/~~D~~M/A	Record keeping

Table VII – B
Applicable Limits and Compliance Monitoring Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
Opacity	BAAQMD ~~6-~~6-1-301	~~Y~~N		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond #136, part 13~~0~~a	P/~~Q~~D	Visible emission monitoring
	SIP 6-301	Y		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond #136, part 13a	P/Q	Visible emission monitoring
	BAAQMD ~~6-~~6-1-301	~~Y~~N		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, parts ~~8 and 9~~11and 12	P/W	Pressure drop monitoring
	SIP 6-301	Y		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, parts 11and 12	P/W	Pressure drop monitoring
	BAAQMD ~~6-~~6-1-301	~~Y~~N		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection
	SIP 6-301	Y		Ringelmann 1.0 for < 3 minutes/hr	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection
FP	BAAQMD 6-1-310	N		0.15 gr/dscf	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
FP	BAAQMD ~~6-~~6-1-310	~~Y~~N		0.15 gr/dscf	BAAQMD Cond. #136, parts ~~8 and 9~~11 and 12	P/W	Pressure drop monitoring
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring

Table VII – B
Applicable Limits and Compliance Monitoring Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
	BAAQMD ~~6~~ 6-1-310	~~Y~~N		0.15 gr/dscf	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection
	BAAQMD ~~6~~ 6-1-310	~~Y~~N		0.15 gr/dscf	BAAQMD Cond. #136, part 13b~~0b~~	P/A	Source test
	SIP 6-310	Y		0.15 gr/dscf	BAAQMD Cond. #136, part 13b	P/A	Source test
	BAAQMD 6-1-310.3	N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
FP	BAAQMD ~~6~~ 6-1-310.3	~~Y~~N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, parts ~~8 and 9~~11 and 12	P/W	Pressure drop monitoring
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring
	BAAQMD ~~6~~ 6-1-310.3	~~Y~~N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13b~~0b~~	P/A	Source test
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 13b	P/A	Source test
	BAAQMD ~~6~~ 6-1-310.3	~~Y~~N		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection

Table VII – B
Applicable Limits and Compliance Monitoring Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
	SIP 6-310.3	Y		0.15 gr/dscf @ 6% oxygen by volume	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection
	BAAQMD 6-1-311	N		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	SIP 6-311	Y		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13a	P/D	Visible emission monitoring
	BAAQMD ~~6-~~6-1-311	~~Y~~N		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, parts ~~8 and 9~~11and 12	P/W	Pressure drop monitoring
	SIP 6-311	Y		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, parts 11and 12	P/W	Pressure drop monitoring
	BAAQMD ~~6-~~6-1-311	~~Y~~N		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 14~~1~~	P/A	Annual baghouse inspection
	SIP 6-311	Y		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 14	P/A	Annual baghouse inspection
	BAAQMD ~~6-~~6-1-311	~~Y~~N		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13~~0~~b	P/A	Source test
	SIP 6-311	Y		4.10P$^{0.67}$ lb/hr but not to exceed 40 lb/hr, where P is process weight, ton/hr; maximum 40 lb/hr	BAAQMD Cond. #136, part 13b	P/A	Source test

Table VII – B
Applicable Limits and Compliance Monitoring Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
	BAAQMD Cond. #136, parts 11 and 12	Y		Pressure drop at the baghouse shall be maintained between 1.0 and 10.0 inches of water gauge except during cleaning and maintenance	BAAQMD Cond. #136, parts 11 and 12	P/W	Pressure drop monitoring
PM10	BAAQMD Cond. #136, part 10	N		29.4 tons in any 12-month period	BAAQMD Cond. #136, part 13b	P/A	Source test
SO2	BAAQMD Regulation 9-1-301	Y		ground level concentrations shall not exceed: 0.5 ppm for 3 consecutive minutes AND 0.25 ppm averaged over 60 consecutive minutes AND 0.05 ppm averaged over 24 hours	BAAQMD Regulation 9-1-501	C	CEM
	9-1-310.2	Y		400 ppm by volume, averaged over one hour or 113 kg per hour, whichever is most restrictive	BAAQMD Cond. #136, part 3	C	CEM
~~SO2~~	~~9-1-310.2~~	~~Y~~		~~113 kg per hour~~	~~BAAQMD Cond. #136, part 3~~	~~C~~	~~CEM~~
SO2	BAAQMD Cond. #136, part 5	Y		749.32 tons in any 12-month period	BAAQMD Cond. #136, part 3	C	CEM
Calcined coke through-put	BAAQMD Cond. #136, part 15b~~2 b.~~	Y		~~182,500~~262,800 tons/yr	BAAQMD Cond. #136, part ~~13 d~~16d	P/M~~D~~	Record keeping
Fuel usage	BAAQMD Cond. #136, part 15b~~2 b.~~	Y		5.00 million therms/yr for S-1 and 2.6 million therms/yr for A-1	BAAQMD Cond. #136, parts ~~13 c~~16a and c	P/~~D~~M	Record keeping

Table VII – B
Applicable Limits and Compliance Monitoring Requirements
S-2 K-2 Coke Calcine Kiln/Cooler

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
Fuel usage	BAAQMD Cond. #3752, part 1	Y		Natural gas firing only	BAAQMD Cond. #3752, part 3	P/A	Records
Fuel usage	BAAQMD Cond. #3752, part 2	Y		5.00 million therms/yr for S-1	BAAQMD Cond. #3752, part 3	P/A	Records

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 IV of the permit.

Changes to permit

Table VIII
Test Methods

Applicable Requirement	Description of Requirement	Acceptable Test Methods
BAAQMD ~~6-~~6-1-301	Ringelmann No. 1 Limitation	Manual of Procedures, Volume I, Evaluation of Visible Emissions
SIP 6-301	Ringelmann No. 1 Limitation	Manual of Procedures, Volume I, Evaluation of Visible Emissions
BAAQMD ~~6-~~6-1-310	Particulate Weight Limitation	Manual of Procedures, Volume IV, ST-15, Particulates Sampling
SIP 6-310	Particulate Weight Limitation	Manual of Procedures, Volume IV, ST-15, Particulates Sampling
BAAQMD ~~6-~~6-1-310.3	Particulate Weight Limitation	Manual of Procedures, Volume IV, ST-15, Particulates Sampling
SIP 6-310.3	Particulate Weight Limitation	Manual of Procedures, Volume IV, ST-15, Particulates Sampling
BAAQMD ~~6-~~6-1-311	General Operations	Manual of Procedures, Volume IV, ST-15, Particulates Sampling

Table VIII
Test Methods

Applicable Requirement	Description of Requirement	Acceptable Test Methods
SIP 6-311	General Operations	Manual of Procedures, Volume IV, ST-15, Particulates Sampling
BAAQMD 8-7-301.6	Limited Leakage	Manual of Procedures, Volume IV, ST-38, Gasoline Dispensing Facility, Static Pressure Integrity, Aboveground Vaulted Tanks
BAAQMD 9-1-301	Limitations on Ground Level Concentrations	Manual of Procedures, Volume VI, Air Monitoring Procedures, Part 1, Ground Level Monitoring for Hydrogen Sulfide and Sulfur Dioxide
BAAQMD 9-1-310.2	Emission Limitations for Coke Calcining Kilns	Manual of Procedures, Volume IV, ST-19A, Sulfur Dioxide, Continuous Sampling, or ST-20, Sulfur Dioxide, Sulfur Trioxide, Sulfuric Acid Mist
BAAQMD Condition #136, Part 6	Sulfuric acid mist testing	Manual of Procedures, Volume IV, ST-12, Determination of Sulfur Dioxide, Sulfur Trioxide, and Sulfur Acid Mist in Effluents
BAAQMD Condition #136, Part 10	Annual PM10 limit	EPA Method 5, Determination of particulate matter emissions from stationary sources
BAAQMD Condition #136, Part 13	Visible Emissions Monitoring	Manual of Procedures, Volume I, Evaluation of Visible Emissions
BAAQMD Condition #17820, Part 3	Determination of PM10 Emissions	CARB Method 501 including CP, Determination of Size Distribution of Particulate Matter from Stationary Sources; or CARB Method 501 including CP, Determination of Size Distribution of Particulate Matter from Stationary Sources, plus CARB Method 5 including CP, Determination of Particulate Matter Emissions from Stationary Sources; or EPA Method 201/201A, Determination of PM10 Emissions, plus EPA Method 202, Determination of Condensible Particulate Emissions from Stationary Sources

IX. Permit Shield:

Changes to permit:
This action proposes no changes to permit shields.

X. Revision History

Changes to permit:
A revision history section will be added with the following information:

Initial Issuance (Application 25817) July 31, 2002

Significant Revision (Application 17331): [enter approval date]

XI. Glossary

Changes to permit:

This action proposes no changes to the glossary.

XII. Appendix A - State Implementation Plan

This section has been deleted. The address for EPA's website is now found in Sections III and IV.

D. Alternate Operating Scenarios:

No alternate operating scenario has been requested for this facility.

E. Compliance Status:

See Section C.V above.

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APPENDIX A

GLOSSARY

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.

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CEM
Continuous Emission Monitor

CEQA
California Environmental Quality Act

CFEP
Clean Fuel Expansion Project

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

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). Cumulative increase is used to determine whether threshold-based requirements are triggered.

District
The Bay Area Air Quality Management District

dscf
Dry Standard Cubic Feet

EPA
The federal Environmental Protection Agency.

EFRT
External Floating Roof Tank

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

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

MOP
The District's Manual of Procedures.

NAAQS
National Ambient Air Quality Standards

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

NH3
Ammonia

NOx
Oxides of nitrogen.

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

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

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

POC
Precursor Organic Compounds

PM
Particulate Matter

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

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

SCR
Selective Catalytic Reduction

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

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

TRMP
Toxic Risk Management Plan

VOC
Volatile Organic Compounds

Units of Measure:

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

APPENDIX B

Engineering Evaluation Application 15328

1.0 BACKGROUND

ConocoPhillips Refining Company (ConocoPhillips) submitted this application for the following:

- **To obtain contemporaneous emission offsets of SO_2 from S2 (K-2 Kiln Burner; abated by A2 Pyroscrubber and A11 Baghouse) for Plant 16, Clean Fuels Expansion Project**

- **To obtain PM_{10} actual emission offsets from S2 (K-2 Kiln Burner; abated by A2 Pyroscrubber and A11 Baghouse) for California Environmental Quality Act (CEQA) purposes for Plant 16, Clean Fuels Expansion Project**

- **To request changes to permit condition 136 to include new SO_2 and PM_{10} emission limits for S2**

ConocoPhillips has previously submitted an Authority to Construct (ATC) and a Prevention of Significant Deterioration application (BAAQMD application number 13424) for the Clean Fuels Expansion Project (CFEP) at its Rodeo Refinery (Plant 16). To offset emission increases from the CFEP, ConocoPhillips has submitted this application for contemporaneous offsets of sulfur dioxide (SO_2) and actual emission offsets of particulate matter (PM_{10}) for CEQA purposes at its Contra Costa Carbon Plant (Plant 22). This application proposes to reduce emissions of SO_2 through increased sodium bicarbonate injection in the gas stream prior to the baghouse system controlling the K-2 Coke Calcine Kiln (S2) and PM_{10} emission reductions through the installation of new bag technology at the K-2 Baghouse (A11).

Contra Costa County, the CEQA lead agency for the CFEP, does not recognize banked offsets for the purposes of CEQA.

The proposed reductions are scheduled to be implemented prior to start-up of the proposed CFEP.

The request for changes to permit condition 136 to include a new SO2 emission limit will be classified as a “Significant” revision per District Regulation 2-6-226.4 because the facility is avoiding the requirement for PSD Modeling for SO_2 that is required pursuant to Regulation 2-2-222.

2.0 EMISSIONS SUMMARY

SO_2 Emissions

S2, K-2 Kiln, is required by Permit Condition 136, Part 3, to operate and maintain a continuous emission monitoring system to quantify:

- The concentration of sulfur dioxide inside each kiln's exhaust stack;
- The flow rate of combustion products from each exhaust stack; and
- The mass emission rate of sulfur dioxide from each exhaust stack into the atmosphere.

Using stack monitoring data for a 3-year baseline period (5/01/03 to 4/30/06) as required by District Regulation 2-2-605, the SO_2 total mass emissions averaged 791.32 tons per year for the K-2 Kiln. Please refer to Attachment 1 for emission details. The project proposes to increase injection of sodium bicarbonate in the gas stream prior to the K-2 Baghouse leading to a reduction of 42 tons per year, thus limiting emissions to 749.32 tons per year. The reduction will be demonstrated by monitoring stack SO_2 emissions and flow rate, and calculating the achieved mass emission rate.

PM_{10} Emissions

ConocoPhillips is also proposing to upgrade the filtration device in the baghouse, which will result in a PM_{10} emissions reduction. Technical information on the new baghouse technology is included in the application folder. The information indicates that the proposed filter bag uses a micro-porous Membrane to enhance airflows, reduce media drag and enhance ash release. Per the information and data provided by the applicant, these filter bags are generally 99.995% efficient at one micron or larger.

For a 3-year baseline period (8/01/2003 to 7/30/2006) as required by District Regulation 2-2-605, the PM_{10} total mass emissions averaged 37.4 tons per year for K-2 Kiln. This data came from three source tests that were conducted in 2004, 2005 and 2006. Please refer to Attachment 2 for emission details including source test results. The proposed upgrade in baghouse technology will lead to a reduction of 8.0 tons per year thus limiting emissions to 29.40 tons per year. The reduction will be demonstrated through annual source testing required by Permit Condition 136 Part 10b.

Table 1 below summarizes the resultant emission reductions from the proposed modifications:

Table 1: Summary of Proposed Emission Reductions at K-2 Kiln

Pollutant (tons/yr)	PM_{10}	SO_2
Current Baseline Emissions (3 years)	37.40	791.32
Proposed Reduction	-8.00	-42
Proposed Emission Limits	29.40	749.32

Note: PM10 emissions estimated assuming for each kiln 2.5 hours per day are spent soot blowing/cleaning using the Cleaning emission factor. The other 21.5 hours per day calculated using the Normal Operation emission factor.

2.1 Plant Cumulative Increase

The cumulative emission increase is zero for all the criteria pollutants because annual emissions for this plant are not increasing due to this application.

2.2 Best Available Control Technology

In accordance with BAAQMD Rule 2-2-301, BACT applies to a modification of any source that results in an increase in emissions. Because the changes to the bicarbonate injection and the baghouse will result in a decrease of emissions, BACT does not apply.

2.3 Toxics

New source review of Toxic Air Contaminants (BAAQMD Rule 2-5) requires the Best Available Control Technology for Toxics (TBACT) for sources that result in cancer risk greater than 1.0 in one million and/or chronic hazard index greater than 0.20. The proposed changes to the Carbon Plant would not result in an increase in toxic emissions, thus the New Source Review of Toxic Air Contaminants does not apply.

2.4 Offsets

Offsets must be provided for any new or modified source at a facility that emits more than 10 tons/yr of POC or NOx. The District may provide offsets from the Small Facility Banking Account for a facility with emissions between 10 and 35 tons/yr of POC or NOx, provided that the facility has no available offsets. Since there is no increase in emissions at this plant as mentioned in Section 2.0 above, offsets are not required for this application.

This application will provide contemporaneous emission offsets of SO_2 and actual emission offsets of PM_{10} for CEQA purposes for CFEP Application 13424 that has been submitted for Rodeo Refinery (Plant 16).

The Emission Reduction Credits (ERCs) calculations of SO_2 were performed in accordance with the procedures outlined in Regulation 2-2-605. ERCs are calculated based on stack monitoring data for a 3-year baseline period (5/01/03 to 4/30/06).

In determining creditable ERCs under Section 2-2-605, the proposed additional SO2 reductions from the kiln were not reduced by a RACT-adjustment due to considerations of the cost-effectiveness of further controls required by Section 2-2-243.

A measure of RACT-level cost effectiveness for new and modified sources is represented by EPA in their recent proposal for 40 CFR 60, Subpart J, Standards of Performance for Refineries. Following are the costs for control of SO2 emissions from various categories that were judged by EPA to be reasonable:

New Fluid Catalytic Crackers	Option 4	$1,000/ton
Modified Fluid Catalytic Crackers	Option 4	1,400/ton
Fluid Cokers	Option 2	210/ton
Sulfur Recovery Plants	Option 2	1,200/ton
Process Heaters/Other Combustion	Option 2	2,200/ton

The ConocoPhillips proposal would use the existing sodium bicarbonate system at the Carbon Plant to achieve the proposed SO2 emission reductions. Since the facility has already installed the system to ensure compliance with the limits in BAAQMD Regulation 9-1-310.2, the additional capital cost of increasing the level of control of SO2 as proposed would be minimal. The operating costs, including disposal of hazardous waste, have been determined to be $2700/ton SO2. This cost of control exceeds all of the cost-effectiveness figures judged by EPA to be reasonable in their recent proposed NSPS.

The District is also aware that the South Coast AQMD has a rule requiring 80% control of SO2 from coke calciners. This level of control has been achieved by the use of a wet scrubber. ConocoPhillips performed an analysis for a similar coke calciner at their Santa Maria refinery in San Luis Obispo County. The capital costs, operating costs, and $/ton removed are shown below:

Process	Capital Cost	Operating Cost	Removal Efficiency	$/ton removed
Wet Scrubber	$8.5 MM	$6.7 MM/yr	95%	$15,000
Dry Scrubber	***$2.3 MM***	***$4.5 MM/yr***	***90%***	***$9,000***

However, the South Coast is a non-attainment area for SO2. The South Coast rule represents a higher level of control that is well beyond RACT.

Based on the considerations of cost-effectiveness summarized above, no RACT adjustments were applied in determining creditable SO2 ERCs from the Carbon Plant kiln control proposal.

Communities for a Better Environment (CBE) made a comment regarding the SO2 offsets during the public comment period. Following is a quote from page 14 of their letter of April 20, 20007, attached:

> ***"…the Project is improperly attempting to use credits for reductions that should have occurred years ago. Major modifications were made at the Carbon Plant in 1976-1977 and in 1983, which should have triggered PSD; the facility should have made the reductions in SO2 emissions (and other pollutants) at that time. Conoco should not be permitted to compound this problem. Conoco cannot now credit current reductions to the New Project…."***

The Carbon Plant was not subject to the PSD regulations in 1976 because the rules did not apply to coke calciners at that time. This issue is more fully explored in the District's response to CBE's comments, attached.

In 1983, the Carbon Plant would have been subject to PSD if the facility had made a major modification. The modification that was made in 1983 was the installation of heat recovery for energy efficiency and a baghouse to reduce particulate emissions. CBE theorizes that the reduction in temperature of the stack gases and a catalytic effect of the metallic surfaces of the heat recovery equipment should have caused an increase in sulfuric acid mist (SAM) over 7 tons per year. The District believes that this argument is highly speculative. In any case, if the District had determined that the modification would have resulted in a significant increase in SAM, the facility would have been subject to limits and/or controls for SAM only, not for SO2. To resolve this issue, the facility will perform source tests to determine the amount of sulfuric acid mist that is currently being emitted within one year of issuance of the Authority to Construct. The results will be compared to the only existing test prior to the 1983 project, which had a result of 6.24 lb SAM/hr from S2, Kiln.

This issue is more fully explored in the District's response to CBE's comments, attached.

3.0 STATEMENTS OF COMPLIANCE

<u>Major Facility Review</u>

The ConocoPhillips Contra Costa Carbon Plant has a Major Facility Review permit as required by BAAQMD Rule 2-6 since it is considered a major source of emissions. ConocoPhillips is proposing to add two new limits to the existing Major Facility Review Permit and new requirements for monitoring and recordkeeping to verify compliance with the proposed emissions reductions. Because the PM10 reductions are voluntary and not required by any Federal, State, or Local rule, the proposed PM10 permit condition will not be federally enforceable. The District agrees with this determination as per guidance provided by the District Assistant Counsel, Kathleen Walsh. Therefore, CEQA will be the basis for this new PM_{10} emission limit permit condition. This will make the new PM_{10} permit condition non-federally enforceable.

The SO2 emission limit will be federally enforceable.

The reduction in SO_2 would be enforced by limiting the mass emissions to 749.32 tons on an annual average basis. ConocoPhillips will continue to be limited by BAAQMD Regulation 9-1-310.2, which states: “A person shall not emit, from any coke calcining kiln, effluent process gas containing sulfur dioxide in excess of 400 ppm by volume or in excess of 113 kg (250 pounds) per hour, whichever is more restrictive. The following permit language that will be included in Permit Condition 136 is proposed to make the 42-ton per year reduction in SO_2 emissions a federally enforceable condition:

> **The owner/operator shall ensure that SO2 emissions from S2 do not exceed 749.32 tons in any consecutive 12-month period. [Basis: Regulation 2-2-303, Offsets]**

The reduction in PM_{10} will be enforced by limiting emissions to 29.40 tons per year on an annual average basis. ConocoPhillips will continue to be limited by BAAQMD Regulations 6-301 and 6-311, which limit particulate concentration and mass emissions. The following permit language that will be included in Permit Condition 136 is proposed to make the 8.0-ton per year reduction in PM10 emissions an enforceable condition:

> **The owner/operator shall ensure that PM10 emissions from S2 do not exceed 29.40 tons in any consecutive 12-month period. The emissions shall be calculated assuming that S2 operates normally for 21.5 hours per day and soot blowing and/or baghouse cleaning occurs for 2.5 hours per day. Normal operating emissions shall be estimated using the emissions from the most recent Condition 136 Part 10b source test. Soot blowing/baghouse cleaning emissions shall be based on an emission rate of 1.412 lb PM10 per ton of coke processed. [Basis: CEQA]**

<u>The California Environmental Quality Act (CEQA)</u>

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 November 2006. 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 September 25, 2007, the final EIR was certified by the Contra Costa County Board of Supervisors. The District must act on the application within 30 days of the certification.

As a responsible agency, the District has prepared findings for the purposes of CEQA. They are attached in Attachment 5.

Prevention of Significant Deterioration (PSD)

The contemporaneous offsets for SO_2 have been included in ConocoPhillips' Clean Fuels Expansion and Hydrogen Plant Projects (CFEP) Permit Application 13424.

As originally proposed, the CFEP project triggered PSD for PM because the PM emissions increase subject to PSD was 16.8 tons per year. ConocoPhillips and Air Liquide have agreed to reduce the "PSD" emissions to 14.5 tons per year. Therefore, the project is no longer subject to PSD.

The upgraded baghouse technology is exempt from PSD requirements because it will not increase emissions, and therefore not exceed any of the thresholds listed in BAAQMD Rule 2-2-304 through 2-2-306 or 40 CFR 52.21.

Public Notification

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.

PSD notification was published for the CFEP application numbers 13424, 13678, and 15328. Comments were submitted by the Good Neighbor Agreement Committee, Communities for a Better Environment, ConocoPhillips, and Air Liquide. The comments and the responses to comments will be part of the application records.

Other Prohibitory Rules

The K-2 Kiln is subject to BAAQMD Regulations 1 (General Provisions), 6 (Particulate Matter and Visible Emissions), and 9-1 (Inorganic Gaseous Pollutants-Sulfur Dioxide). After the proposed project is completed, the K-2 Kiln will continue to satisfy the applicable requirements.

NSPS and NESHAPS do not apply.

4.0 PERMIT CONDITIONS

Current permit condition 136 applicable to sources S1 and S2 will be modified as follows to include new SO_2 and PM_{10} emission limits for S2, K-2 Kiln:

A change to the permit condition was made after public comment and after the EIR was certified. The final conditions of approval adopted by the county included a settlement between the California Attorney General and ConocoPhillips. One of the items in the settlement was the closure of the Santa Maria Carbon Plant in San Luis Obispo County. A question arose about whether the coke from the Santa Maria Refinery would be calcined at the ConocoPhillips Carbon Plant in Rodeo. In response to this question, the facility agreed to a permit condition that prohibits calcining of the Santa Maria coke in Rodeo.

COND# 136 --------------------------------------

Condition #136
For: S1 K-1 Coke Calcine Kiln/Cooler
S2 K-2 Coke Calcine Kiln/Cooler

Any condition that is preceded by an asterisk is not federally enforceable.

1. All pyroscrubber access ports shall be closed during source tests conducted to determine compliance with District regulations and/or permit conditions.
(Basis: Regulation 1-401)

2. APCO approved sampling ports and access platforms shall be provided downstream of each baghouse.
(Basis: Regulation 1-501)

3a. The permit holder shall operate and maintain a continuous emission monitoring system to quantify:
a. the concentration of sulfur dioxide inside each kiln's exhaust stack, and
b. the flowrate of combustion products from each exhaust stack, and
c. the mass emission rate of sulfur dioxide from each exhaust stack into the atmosphere.
(Basis: Regulations 1-521 and 522)

3b. The permit holder shall use gas flow meters to record the flow of natural gas to the kilns and pyroscrubbers. (Basis: Regulation 2-6-503)

4. The continuous emission monitoring system shall meet the requirements of the Manual of Procedures, Volume V, Continuous Emission Monitoring Policy and Procedures (Basis: Regulation 1-522)

5. The owner/operator shall ensure that SO_2 emissions from S2 do not exceed 749.32 tons in any consecutive 12-month period. [Basis: Regulation 2-2-303, Offsets]

6. Within one year from the issuance of the Authority to Construct number 15328, the owner/operator shall conduct District-approved source tests to determine hourly sulfuric acid mist emissions from S1 and S2, Kilns. The owner/operator shall submit protocols for all source test procedures to the District's Source Test Section at least three weeks prior to conducting any tests. The owner/operator shall notify the District's Source Test Section, in writing, of the projected test dates at least 7 days prior to testing. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test. (basis: Regulation 2, Rule 5, PSD)

7.In order to demonstrate compliance with the parts 3, 4, and 5 of this condition, the following records shall be maintained in a District approved log. These records shall be kept on site and made available for District inspection for a period of 5 years from the date on which a record is made:

a. the concentration of sulfur dioxide inside each kiln's exhaust stack, as prescribed in part 3 of this condition.
b. the mass emission rate of sulfur dioxide from each exhaust stack into the atmosphere, as prescribed in part 3 of this condition.
c. Amount of natural gas burned on a monthly basis (therms/month).
d. Continuous emission monitoring measurements for sulfur dioxide.
e. Date, time, and duration of any startup, shutdown, or malfunction of any kiln, emission control equipment, or emission monitoring equipment.
f. Results of performance testing, evaluations, calibrations, checks, adjustments, and maintenance of any CEMs.
g. Hourly sulfur dioxide concentration and emission rate
h. Annual sulfur dioxide emission rate in tons at S2 to ensure compliance with part 5 of this condition.
i. Hourly flow rate of combustion products
(basis: Regulation 1-441, Regulation 2-2-303, Offsets)

*8. The permit holder shall keep the Baghouses, A10 and A11 in good operating condition. (basis: Regulation 6-301)

9. All particulate matter emissions from S1 and S2 shall be routed to the baghouses A10 and A11, respectively. (basis: Regulation 6-301, 6-310, 6-311)

*****10. The owner/operator shall ensure that PM_{10} emissions from S2 do not exceed 29.40 tons in any consecutive 12-month period. The emissions shall be calculated assuming that S2 operates normally for 21.5 hours per day and soot blowing and/or baghouse cleaning occurs for 2.5 hours per day. Normal operating emissions shall be estimated using the emissions from the most recent Condition 136 Part 12b source test. Soot blowing/baghouse cleaning emissions shall be based on an emission rate of 1.412 lb PM10 per ton of coke processed. [Basis: CEQA]

11. Within 3 months of final issuance of the Major Facility Review permit, the permit holder shall

install a District approved manometer or other District approved device which measures the pressure drop across each baghouse. Within 6 months of final issuance of the Major Facility Review permit, the permit holder shall determine the proper pressure drop range for each baghouse. These ranges shall be submitted to the Permits Division of the District for inclusion in the permit as an administrative permit amendment. (basis: Regulation 2-6-409.2)

12. After installation of the manometer or devices, the manometer or device shall be operational at all times that the above sources are operated. The pressure drop across the baghouses shall be recorded once a week to ascertain that the pressure drops are in the normal operating range, and the baghouses are in good operating condition. The records shall be kept on site for at least five years from the date of data entry and be made available to the District staff for inspection. (basis: Regulation 2-6-409.2 and 2-6-501)

13. a. Visible particulate emissions from S1 and S2 shall be monitored quarterly using the District method (Manual of Procedures, Volume I, Evaluation of Visible Emissions) and shall be retained on site for a minimum period of five years from the date of data entry and be made available to the District staff for inspection. (basis: Regulation 6-301, Regulation 2-6-501)

b. The owner/operator of S1 and S2 shall conduct an annual District-approved source test at each furnace in order to demonstrate compliance with Regulation 6-310, 6-310.3 and 6-311. The results of these tests shall be kept on site for at least five years from the date of the test and be made available to District staff upon request.
(basis: Regulation 2-6-501)

14. Each baghouse shall be inspected on an annual basis to ensure proper operation. Records of each annual inspection shall be kept on site for at least five years from the date of data entry and be made available to the District staff for inspection.
(basis: Regulation 2-6-501)

15. Natural gas usage and calcined petroleum coke produced shall not exceed the following in any consecutive 12-month period:

a. For S1:
Natural gas usage at the S1 burner: 5.25 million therms
Natural gas usage at the A1 burner: 2.6 million therms
Calcined petroleum coke produced: 262,800 tons

b. For S2:
Natural gas usage at the S1 burner: 5.00 million therms
Natural gas usage at the A1 burner: 2.6 million therms
Calcined petroleum coke produced: 262,800 tons
(basis: Regulation 2-1-234.3)

16. The permit holder shall maintain the following records for each limit listed in parts 10 and 15:

a. Monthly natural gas usage per burner and per source
b. Monthly calcined petroleum coke produced per source
c. Total natural gas usage per burner and per source for the preceding 12 months
d. Total calcined petroleum coke produced per source for the preceding 12 months
e. Annual PM10 emission rate in tons at S2 to ensure compliance with part 10 of this condition.
(basis: Regulation 1-441, CEQA)

17. The permit holder shall make available to the APCO, upon request, any records relating to hourly or daily fuel usage or coke throughput.
(basis: Regulation 1-441)

18. The ConocoPhillips Carbon Plant shall not calcine any coke from the Santa Maria refinery. [Offsets, CEQA]

5.0 RECOMMENDATION

Staff recommends the following:

a. Grant contemporaneous emission offsets of SO_2 in the amount of 42 tons per year from S2 (K-2 Kiln Burner; abated by A2 Pyroscrubber and A11 Baghouse) for Plant 16, Clean Fuels Expansion Project

b. Grant actual emission offsets of PM_{10} in the amount of 8.00 tons per year from S2 (K-2 Kiln Burner; abated by A2 Pyroscrubber and A11 Baghouse) for Plant 16, Clean Fuels Expansion Project

c. Approve changes to permit condition 136 to include new SO_2 and PM_{10} emission limits for S2, K-2 Kiln Burner and requirement for one-time source test for sulfuric acid mist.

By: ***Brenda Cabral for Sanjeev Kamboj***
Sanjeev Kamboj
Air Quality Engineer II

Date October 5, 2007

ATTACHMENT 1

Three-Year Baseline Emission for SO_2 from the Carbon Plant

ATTACHMENT 2

Three-Year Baseline Emission for PM_{10} from the Carbon Plant

ATTACHMENT 3

Letter of April 20, 2007 from Communities for a Better Environment to BAAQMD regarding CFEP project

ATTACHMENT 4

BAAQMD Response to letter of April 20, 2007 from Communities for a Better Environment regarding CFEP project

October 5, 2007

Shana Lazerow
Staff Attorney
Communities for a Better Environment
1440 Broadway, Suite 701
Oakland, CA 94612

Subject: Response to comments on ConocoPhillips CFEP Project,
Applications 13424, 13678, and 15328

Dear Ms. Lazerow:

The District wishes to thank Communities for a Better Environment for commenting on the CFEP project in Julia May's letter of April 20, 2007.

The District has reviewed all comments and has made some changes prior to finalizing the Authorities to Construct. The Authorities to Construct were issued today. Copies of the final evaluations and Authorities to Construct will be sent to you via email at the following address: slazerow@cbecal.org.

The responses to your comments and to comments by the Good Neighbor Agreement Committee, ConocoPhillips, and Air Liquide are attached.

The District would like to inform you that ConocoPhillips and Air Liquide have decided to reduce the amount of particulate matter that will be emitted by the project so that the project is no longer subject to the Prevention of Significant Deterioration requirements. This change is fully explained in the amended evaluations.

If you have any questions on this matter, please call **Brenda Cabral, Supervising Air Quality Engineer at (415) 749-4686**.

Very truly yours,

Jack P. Broadbent
Executive Officer/APCO

by
Engineering Division

Attachments

BFC

RESPONSE TO CBE COMMENTS

(Page 1)
CBE:
Comment I: This refinery is already a major source of odors even before this major expansion begins. Conoco should remedy existing causes of odors first. Processing of highly sulfur-laden products will increase.
Response: ConocoPhillips is proposing to control 0.63 tons H2S per year at S1007, Dissolved Air Flotation Unit (DAF) by installing a thermal oxidizer. H2S is by far the largest contributor to odors at refineries. The DAF has atmospheric vents. The emissions from the DAF have poor dispersal because the vapors are emitted at low velocity and because the openings of the vents are near ground level. Abating these emissions with a thermal oxidizer, and venting through a stack, should reduce the odors experienced off-site.

ConocoPhillips is also adding several tanks to the odor abatement system, and installing a fourth odor abatement compressor. The new compressor will make their system more reliable and will also provide a back-up to the flare gas recovery compressor, which will reduce flaring, and therefore, odors.

ConocoPhillips will improve the monitoring for the tanks on the odor abatement system. The District will impose a permit condition requiring ConocoPhillips to monitor the pressure in each tank to determine whether the pressure relief valves have lifted resulting in emissions to the atmosphere. Corrective action is required if a pressure relief valve lifts 3 times in one year.

It is true that processing of highly sulfur-laden products will increase at the new cracking unit. However, the new unit will have a high-pressure rating. Due to this design, ConocoPhillips does not expect to vent high volumes of gas from the new cracking unit to the flare. ConocoPhillips will have to include any flaring caused by the new unit in their annual SO2 limit for this project.

The sulfur recovery units will treat the refinery fuel gas that is generated by the unit. ConocoPhillips is installing a fourth sulfur recovery unit to ensure that it has sufficient capacity to recover the sulfur.

Comment Ia: District has underestimated fugitive emissions of H2S.
Response: As discussed in the response to Comment 1, ConocoPhillips is proposing to control 0.63 tons H2S at S1007, Dissolved Air Flotation Unit (DAF).

It is true that there is a proposed increase of about 1 ton H2S per year from S1004, SRU, but the unit has a low concentration limit, 2.5 ppmv @ 0% oxygen, and a high stack that will ensure proper dispersal to minimize odors. Compliance with the concentration limit will be ensured by source tests.

ConocoPhillips also has H2S sensors in the sulfur recovery area for safety reasons. These sensors indicate the H_2S level and trigger an alarm at a concentration of 10 ppm. The new Sulfur Plant will incorporate additional field H_2S sensors. The Refinery operates Ground Level Monitors for H2S off-site. Also, all personnel in the Refinery are required to wear a Personal Health Monitor that alarms at an H2S level of 10 ppm. It is the District's understanding that the alarms rarely go off.

(Page 3)
Comment II: Inconsistencies between regulations were not resolved in favor of the most stringent requirements and some emissions estimates are missing.

Comment II.a: Several refinery sources were omitted.
See response to comments II.B.2, II.B.3, II.B.4 and II.B.5.

Comment II.B.1: Sulfuric acid mist (SAM) exceeds the PSD threshold; Sulfuric acid mist should be rounded up from 6.64 tpy to 7 tpy.
Response: The commenter states that for the 1-hour ozone standard EPA has rounded to one significant digit. However, the standard is in two significant digits: 0.12 ppm. The quote from an EPA Website discussion entitled "Determination of Attainment of the 1-hour Ozone Standard for San Diego County, CA", states that "We have clearly communicated the data handling conventions for the 1-hour ozone NAAQS in regulation and guidance documents…" We agree that EPA has communicated clearly regarding the NAAQS. However, there is no reason to suppose that EPA has chosen this convention for the PSD regulations. The regulation is silent on rounding for this standard. Different regulations define the same terms differently, so the District disagrees that the rounding procedure for the NAAQS should be generalized to the PSD regulations. The PSD analysis required under BAAQMD Regulation 2-2-306 is also triggered only if the specified annual amounts are exceeded.

Comment II.B.2: Sulfuric acid mist from the DAF incinerator was left out of calculations.
Response: The SAM from the DAF incinerator was inadvertently left out of the calculations. The SO2 was calculated at 1.2 ton/year. If approximately 5% of SO2 is converted to SO3, which was the conservative assumption for the other SO2 sources, approximately 0.09 tons SAM/yr will be generated at this source, bringing the total to 6.73 ton/year.

Comment II.B.3: The sulfuric acid mist from the hydrogen plant flare was left out of the calculations.
Response: The sulfur in the feed to the hydrogen plant is expected to be negligible, so the flare will be an insignificant source of SAM.

Comment II.B.4: Regular flaring would increase by 30% with an increase in SAM emissions.
Response: Flaring from existing units is not expected to increase. In fact, flaring is expected to decrease due to implementation of the flare minimization plans required by BAAQMD Regulation 12, Rule 12, Flares at Petroleum Refineries. New flaring may occur from the new processes at S434, U246 High Pressure Reactor Train, and S1004, U235 Sulfur Recovery Unit. Any flaring from these new units must be included in the annual emission limits in BAAQMD Condition 22970, part A.2, which includes a sulfuric acid mist limit. If the SAM emissions from these sources exceed 6.01 ton/yr, the facility is required to submit the PSD analysis. The hydrogen furnace may also emit up to 0.43 tons per year of sulfuric acid mist, but the hydrogen plant flare is not expected to be a source of sulfuric acid mist.

Comment II.B.5: Sulfuric acid mist will be increased by use of SCR.
Response: It is unlikely that sulfuric acid mist will be increased by use of SCR. The amount of sulfuric acid mist will be determined by source test. If the project exceeds 7 tons sulfuric acid mist, which the District believes is unlikely, the facility will have to evaluate the air quality impacts of the higher emissions and submit the results to the District.

Comment II.B.6: SO3 and sulfuric acid mist has an impact on human health.
Response: It is understood that most of the SO3 is converted to sulfuric acid mist. The sulfuric acid mist was included in the risk assessment for the project and the risk was within acceptable limits. Also, the emissions of SO3 have been estimated very conservatively assuming a 5% conversion of SO2 to SO3. It is expected that less than 5% of the SO2 will in fact be converted to SO3, and therefore, H2SO4. This expectation will be confirmed by source testing. We have not calculated the drop in SO3, etc., by reducing emissions of SO2 by 42 tons at Facility A0022, ConocoPhillips Carbon Plant. If the emissions decrease is calculated assuming a 5% conversion of SO2 to SO3, as the engineering evaluation assumes, the decrease in SAM would be 3.2 tons per year. This reduction will ensure that the net increase in SAM does not exceed 7 ton/yr.

Comment II.C: Other emissions were underestimated.
Comment II.C.1: Reduced sulfur compound emissions were underestimated. Only certain compounds were included.

Response: The PSD regulations do not define "Reduced Sulfur Compounds" and "Total Reduced Sulfur." The compounds that are considered to be "Reduced Sulfur Compounds" and "Total Reduced Sulfur" are the compounds defined by and measured by EPA test methods. Method 15A, Determination of Total Reduced Sulfur Emissions from Sulfur Recovery Plants in Petroleum Refineries, defines reduced sulfur compounds as hydrogen sulfide, carbonyl sulfide, and carbon disulfide. Method 16A, Determination of Total Reduced Sulfur Emissions from Stationary Sources (Impinger Technique), defines total reduced sulfur as hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide.

Comment II.C.2: Beryllium emissions were not estimated.
Response: The commenter has not submitted usable data to estimate beryllium emissions. The EVISA document submitted has a global number for refineries in the UK, without any detail of the particular sources where beryllium may be emitted. Without more detail, it cannot be determined whether the data is accurate and where the emissions occur.

ARB's CATEF database has a number of tests on beryllium emissions for refinery fuel gas combustion. The following tests have A and B ratings, which means that the tests were conducted properly: ID #980, 2772-2777, 3013-3016. For these tests, the detection ratio was "0.00." This means that no beryllium was detected and that the numbers represent the level of detection. The District concludes that, absent better data, there are no beryllium emissions from combustion of refinery fuel gas.

Judging from the preamble for the proposal of the second Refinery MACT, 40 CFR 63, Subpart UUU, dated September 11, 1998, EPA believes that beryllium is emitted from fluid catalytic crackers and catalytic reformers, and the final standard does have controls for metals for these sources. EPA did not impose controls on fuel combustion sources, sulfur recovery units, or stationary hydrocrackers. The implication is that these are not significant sources of beryllium. This project does not include a fluid catalytic cracker.

We understand that there may be some beryllium in crude oil, but it is a solid and is therefore unlikely to make its way to the refinery fuel gas.

MACT II for refineries (40 CFR 63, Subpart UUU) addresses beryllium from fluid catalytic crackers, but does not consider beryllium to be emitted by the reformers and SRUs, which it also regulates. It may be inferred that EPA does not consider reformers and SRUs to be sources of beryllium. Bob Lucas of EPA, the author of MACT II, has confirmed that EPA has no emissions data for beryllium for the reformers or SRUs.

(Page 9)
Comment III: Refinery sources of SO2 emissions were not evaluated and offsets not valid.

Comment III.a: The PSD netting analysis is incorrect-SO2 emissions are underestimated. At least 30 additional tons of SO2 will be emitted due to additional flaring. Flaring from dirtier processes, i.e., cracking, will result in higher SO2 emissions.
Response: Flaring from existing units is not expected to increase. In fact, flaring is expected to decrease due to implementation of the flare minimization plans required by BAAQMD Regulation 12, Rule 12, Flares at Petroleum Refineries. New flaring may occur from the new processes at S434, U246 High Pressure Reactor Train, and S1004, U235 Sulfur Recovery Unit. Any flaring from these new units must be included in the annual emission limits in BAAQMD Condition 22970, part A.2, which includes an SO2 limit.

Comment III.b: Shell Martinez represents BACT for flaring and Conoco should be required to add the same equipment and procedures. In essence, Conoco should have a backup compressor. A dual-use compressor was tried by Chevron and it didn't work.
Response: The comment refers to the existing flares. The District did not determine that the existing flares were subject to BACT requirements.

However, the facility is indeed proposing to add an odor abatement compressor that will be used as a backup to the flare gas recovery compressor. This compressor should reduce flaring that occurs when the flare gas recovery compressor malfunctions or is undergoing routine maintenance. ConocoPhillips's flaring system is simpler than Chevron's. There is only one main flare and one backup flare. Just because a dual-use compressor did not work at Chevron does not mean that it will not work at ConocoPhillips.

Comment III.c: Carbon Plant emission offsets are not valid because increases of NOx at the Carbon Plant were not evaluated. More coke will be processed at the plant due to this project.
Response: There will be no increases of NOx at the Carbon Plant due to this project. This project does not include an increase in coke production at the refinery.

Comment III.d: Carbon Plant emission offsets are not valid because Carbon Plant had increases in 1976-1977 and 1983 that should have subject to PSD. These emissions cannot be used for offsets.
Response: The Commenter supports its assertion that the Carbon Plant had modifications in 1976-1977 and 1983 that should have triggered PSD only by reference to a letter dated April 22, 2002, from Adams & Broadwell (A&B) commenting on a draft Title V permit for Facility A0022, ConocoPhilips Carbon plant.

A&B’s April 22 letter, on which Commenter relies, does not claim that the 1976-1977 modification was subject to PSD. To the contrary, at page 9 of the letter, A&B states that it did not evaluate the 1976-1977 modifications to determine whether they triggered PSD. Thus, the April 22 letter does not support the Commenter’s assertion that the 1976-1977 modifications were subject to PSD.

At any rate, the facility was not subject to PSD in 1976. The PSD regulations that were promulgated on December 5, 1974, only applied to eighteen types of facilities, which did not include coke calciners. These were:

(i) Fossil-fuel steam electric plants of more than 1000 million British thermal units per hour heat input
(ii) Coal cleaning plants
(iii) Kraft pulp mills
(iv) Portland cement plants
(v) Primary zinc smelters
(vi) Iron and steel mills
(vii) Primary aluminum ore reduction plants
(viii) Primary copper smelters
(ix) Municipal incinerators capable of charging more than 250 tons of refuse per 24 hour day
(x) Hydrofluoric, sulfuric, or nitric acid plants
(xi) Petroleum refineries
(xii) Lime plants
(xiii) Phosphate rock processing plants
(xiv) Coke oven batteries
(xv) Sulfur recovery plants
(xvi) Carbon black plants (furnace process)
(xvii) Primary lead smelters
(xviii) Fuel conversion plants

The carbon plant is not a petroleum refinery or a coke oven battery. In addition, it was not part of the ConocoPhillips (then Union Oil) refinery at the time, but was owned by Collier Carbon.

Moreover, the project files show that the project in 1976-1977 did not result in emission increases. The purpose of the projects proposed in Applications 15755 and 26080 in 1976 and 1977, respectively, was to introduce air into the calciner kilns so that the process would burn more coke for calcining and the facility could purchase less natural gas for calcining. The applicant thought that this would result in an increase of SO_2 emissions, which was estimated at 12 lb/hr/kiln or 53 tons/yr. After the first project was built, the applicant found that more sulfur was retained in the coke and that the SO2 emissions did not increase. This project resulted in a decrease of greenhouse gas emissions because less natural gas was burned.

In regards to the 1983 project (Application 28445), the commenter again relies on the pertinent portions of A&B's April 22, 2002, letter, which may be summarized as follows:

> A cogeneration plant was added to the Carbon Plant in 1983. The Carbon Plant should have been subject to PSD due to increases of NOx and sulfuric acid mist (SAM). The two pyroscrubbers at 30 MMbtu/hr each would have been sources of NOx and combustion of particles would contribute to fuel NOx.

A&B estimated an increase in natural gas usage of 497,600 MMbtu/hr at the pyroscrubbers, which is an exaggeration. At 30 MMbtu/hr for each of two pyroscrubbers, the maximum potential usage is 525,600 MMbtu/yr. A&B alleges that the pyroscrubbers were used occasionally before installation of the cogeneration plant, and constantly after the installation. There is no documentation that shows that the pyroscrubbers were used infrequently in the application records. In fact, in the documents that A&B submitted to document the increase, the applicant's consultant, Fredereksen Engineering, clearly states that the average usage over the previous three years was 436.5 MMscf/yr or 458,325 MMbtu/yr. In contrast, the amount of natural gas used in 2006 for calciners and pyroscrubbers was 270,000 MMbtu/yr.

The purpose of Application 28445 was to recover waste heat from the exhaust of the calciners and pyroscrubbers and use it to make steam for the purpose of generating electricity, an energy-saving project that generates about 10 MW.

If there had been an increase of 497,600 MMbtu/hr at the pyroscrubbers, the maximum increase of NOx would have been about 25 tons/year, which is below the major modification threshold, using the NOx emission factor of 100 lb/MMscf for small uncontrolled boilers, from Table 1.4-1 of AP-42. This increase was, and is, below the thresholds for a major modification, and therefore, would not have made the project subject to PSD for NOx. In any case, the District made the judgment in 1983 that there would not be an increase in the amount of natural gas used and therefore in the NOx emissions.

In regards to the SAM, A&B alleged more SAM would be generated by the cogeneration project because the effluent of the calciners/pyroscrubbers would be cooled from 1600 to 400 degrees Fahrenheit. A&B alleged that the internals of the heat recovery equipment would likely act as a catalyst for the generation of SO3 (and therefore, acid mist) from SO2. A&B goes on to say that if the District had realized that there would be an increase, that the District would have had the authority to subject the facility to PSD for SO2 and that the facility would have been required to reduce the SO2 emissions by 80% percent, and so, the facility would not have been able to generate offsets by reducing SO2 emissions at the Carbon Plant.

A&B is mistaken about the effect of a higher SAM estimate. There was no increase in SO2 generation. Therefore, the District would not have had the authority to impose new conditions on SO2 without rulemaking. The District would likely have imposed a limit and controls on SAM that would have allowed the plant to stay below the PSD trigger for SAM. Therefore, the SO2 offsets are valid.

Moreover, the alleged increase in SAM is highly speculative. Baghouses were installed at the same time that the cogeneration equipment was installed. It is also possible that because the effluent is cooled to 400 degrees F that the particles that are generated agglomerate at the lower temperature; and that the particles are then trapped by the baghouses. Some sodium bicarbonate is injected into the effluent before the baghouses to ensure compliance with the SO2 limit. This may also reduce the amount of SAM that is emitted.

There is one source test in 1982 that shows that S2 emitted 6.24 lb/hr of acid mist at that time. There are no subsequent source tests. The District will require a source test on both kilns to determine whether there has been an increase or decrease in emissions of SAM. Please understand that a result that is within 25% of the 1982 result would be considered within normal variation and would not be considered indicative of a true increase or decrease.

Comment III: SO2 limit for Carbon Plant should not be an annual limit.
Response: The Carbon Plant has hourly limits in BAAQMD Regulation 9-1-307.2 of 400 ppm SO2 by volume or 250 lb/hr, whichever is most restrictive. Since the purpose of the new SO2 limit of 749.32 ton/yr is to provide SO2 offsets, and offsets are considered to be provided on an annual basis, an annual limit is proper in this case. Since the unit has an SO2 CEM, ConocoPhillips will be able to tell on an ongoing basis if they are in compliance with the annual limit.

Page 14:
Comment IV. BACT and Offsets for PM10 sources are missing
Response: The following sources will not emit more than 10 lb PM10/day and therefore are not subject to BACT for PM10:

- S1004, U235 Sulfur Recovery Unit
- Facility A0016: S98, S122, S123, S124, S128, External Floating Roof Tanks
- Facility A0016: S307, S308, S309, S318, S339, S432, S434-Process Units
- Facility A0016: S1007, Dissolved Air Flotation (DAF) Unit
- Facility B7419: S4, Cooling Tower

The following sources will emit more than 10 lb PM10/day and therefore are subject to BACT for PM10:

- Facility A0016: S45, Heater
- Facility B7419: S2, Hydrogen Plant Furnace

BACT for both sources is the use of gaseous fuel. The commenter mentions that control of sulfur in gaseous fuel is a way to reduce PM10 emission from combustion sources. S45 and S2 have extremely low total sulfur limits.

The PM10 emissions at S2 at Facility A0022 will decrease and therefore the source is not subject to BACT for PM10. The baghouse at S2 will be improved to lower PM10 emissions and to provide offsets for CEQA mitigation for the project.

As discussed in Section 4 of the permit evaluation for Application 13424, 29.42 tons per year of PM10 emissions must be offset. 16.78 tons of PM10 emissions will be attributed to Application 13424 for the refinery and Application 13678 for the hydrogen plant. In addition, 12.64 tons per year must be offset for Applications 5814, 11293, and 12412. All of these offsets, except for the contemporaneous offsets, must be secured before the Authority to Construct is issued. One omission from the discussion in Application 13424 is the fact that 8 tons PM10/yr will be obtained by reductions at S2, Kiln, at the carbon plant. This discussion will be corrected before issuance.

Page 15:
Recommendation #1: Re-evaluate flaring emissions.
Response: See response to comments II.B.4 and III.a.

Recommendation #2: Require additional compressor capacity.
Response: See response to CBE Comment III.b.

Recommendation #3: Meet Shell standard for flare minimization.
Response: See response to CBE Comment III.b.

Recommendation #4: PSD thresholds for SO2 have been exceeded.
Response: See response to CBE Comment III.d.

Recommendation #5: Perform audit of odor problems, more rigorous reporting and evaluation
Response: See discussion of improvements to monitoring of the odor abatement in the response to CBE Comment I.

Recommendation #6: Perform up-to-date BACT analysis for SRU, 50 ppm SO2 limit is 14 years old
Response: The facility has agreed to lower the annual SO2 emissions from the SRU from 36.7 to 29.7 tons per year. If the facility produces 73,000 tons sulfur per year, as allowed, the SO2 emissions would decrease from approximately 1 lb to approximately 0.8 SO2/long ton sulfur produced. Alternately, the facility may comply by reducing production.

Recommendation #7: Re-evaluate project using most stringent regulations
Response: The District has used the appropriate regulations.

Response to Good Neighbor Agreement Committee Comment of 4/11/07

Comment 1: Increase of 23.8 tpy of particulate and 267 lb SO_2/day in Crockett are significant impacts.
Response: The refinery has agreed to drop the proposed SO_2 emissions at the sulfur recovery unit from 36.7 to 29.7 tons per year, which is equivalent to 38 lb per day. 42 tons SO_2 per year and 8 tons particulate per year will be reduced at the Carbon Plant. The increase in actual emissions of SO_2 and particulate will be less than 80 pounds per day, which is less than the CEQA significance thresholds.

Comment 2: Data should be presented on the levels of $PM_{2.5}$ produced at the refinery and the additional $PM_{2.5}$ produced from the expansion proposal.
Response: The exact amount of $PM_{2.5}$ that is produced at the refinery is uncertain. The total amount of particulate estimated by the District is about 121 tons per year for the refinery and 63 tons per year for the carbon plant, based on the calculations in 2005, but would include particulate larger than $PM_{2.5}$. The CFEP project will add about 8.9 tons per year, considering contemporaneous offsets. The particulate emissions from CFEP are generated from combustion; therefore most of the particulate will be $PM_{2.5}$.

Comment 3: Particulates, both 2.5 and 10 um, are currently already nonattainment for CAAQS in this area. The additional 89 lbs/day from this project will push it further from attainment.
Response: Controls at the carbon plant will lower the particulate emissions from 92 lb/day (16.9 tons per year) to 48.8 lb/day (8.9 tons per year).

Currently, the Bay Area is designated as "attainment" for CO, NO_2, SO_2, and lead, which means that the air quality in the Bay Area meets federal and state standards for those pollutants. The Bay Area is designated as "non-attainment" for the state and federal ozone standards and for the state standards for fine particulate matter (PM_{10} and $PM_{2.5}$). New, more stringent federal standards for fine particulate matter have recently been adopted, but EPA has not yet made a designation for the Bay Area for those standards.

These air quality standards apply to the Bay Area as a whole. Thus, the fact that Rodeo may be in an "attainment" area or a "non-attainment" area for a given pollutant does not mean that the air quality in Rodeo is any better or worse than anywhere else in the Bay Area, and does not mean that the proposed project will have any greater or lesser impacts on air quality if it is operated in Rodeo as opposed to any other location in the Bay Area.

The fact that the Bay Area is designated as "non-attainment" for certain pollutants does not mean that no new projects can be built. The District does not prohibit all new projects as a result of a "non-attainment" designation. Instead, the District requires new projects – including the proposed CFEP Project – to incorporate strict air pollution controls to ensure that emissions are minimized, and also requires new sources of emissions to be "offset" by shutting down , or otherwise reducing emissions from, older sources of emissions so that there is no net increase as a result of the new project. This process ensures that regional emissions will continually be reduced in order to bring the region into "attainment" for all regulated pollutants.

The District's regulatory system has a good track record in this regard. Air quality in the Bay Area has been improving over time. The region still faces challenges in meeting the air quality standards for ozone and fine particulate matter, and the District is continuing to develop strategies for the region to achieve compliance with these standards. The latest information is available on our website (www.baaqmd.gov) under the following topics:

BAAQMD - Bay Area Ozone Strategy
BAAQMD - Particulate Matter

Comment 4: The increase of 175 gal sour water/min is a huge potential source of odors.
Response: The processing of sour water would be in a closed system that is not likely to be the source of emissions. The most likely source of odors from sour water would be at the tanks that store sour water previous to processing. Odors from these tanks are controlled by the odor abatement system, a system that collects vapors from these tanks and conveys them to the fuel gas system. The District has imposed monitoring conditions on the sources attached to the odor abatement system. These will enable the facility and the company to determine whether there are malfunctions of the control on these odorous sources.

Comment 5: There have been odors on a daily basis over the past year. Since Conoco has not been able to solve them, they should not be allowed to increase production.
Response: The monitoring on odorous tanks mentioned in the response to comment 4 above and other actions will alleviate the release of odors. The proposals mentioned by Mr. Phil Stern of ConocoPhillips in his email to you of March 6, 2007, which are already part of the project, will all contribute to fewer odors. These are:

- Installation of fourth odor abatement compressor
- Vapor control on gas oil tanks
- Use of the new odor abatement compressor as a backup to the flare gas compressor
- Installation of fourth sulfur recovery plant
- Installation of sulfur degassing facility
- Control of dissolved air flotation unit
- Reduction of loading of heavy gas oil onto marine vessels

Comment 6: The community requests the following mitigations:

a. Reductions in particulate and SO2
b. BACT for tank roofs, seals, and valves to control odors
c. H2S, mercaptan, particulate 2.5, and HC monitors in Bayo Vista, Tormey, and western Crockett between Lillian and Rose Streets with monitor readouts available in real time on county hazmat web site
d. Upgrade to the fence line monitor to detect odor causing chemicals

Response to 6a: The facility has agreed to lower particulate emissions by 0.5 tons per year and SO2 emissions by 7 tons per year.

Response to 6b: The affected external floating roof tanks (S122, S123, S124, and S128) in this application will be controlled to BACT levels. All new valves in gaseous and light liquid service will be BACT valves. Most new valves in heavy liquid service will be BACT valves.

Response to 6c: The District does not have the resources to install ground level monitors for H2S, mercaptan, PM2.5 and HC in Bayo Vista, Tormey, and western Crockett between Lillian and Rose Streets at this time. Please note that the refinery has a ground level monitoring system for SO2 and H2S to comply with District requirements.

Response to 6d: The District understands that the refinery has agreed to upgrade the fenceline monitoring system from infrared analyzers to ultra-violet analyzers and has agreed to other maintenance items.

Response to Good Neighbor Agreement Committee Comment of 4/15/07

Comment 1: Air quality has declined because odors have increased and SO_2 is higher than normal as shown by the Crockett monitor.
Response: The refinery has agreed to reduce odors in the following ways:

- ConocoPhillips is proposing to control 0.63 tons H_2S per year at S1007, Dissolved Air Flotation Unit (DAF) by installing a thermal oxidizer.
- ConocoPhillips is also adding several tanks to the odor abatement system.
- ConocoPhillips is installing a fourth odor abatement compressor, which will make the odor abatement more reliable and will also provide a back-up to the flare gas recovery compressor, which will reduce flaring, and therefore, odors.
- ConocoPhillips will improve the monitoring for the tanks on the odor abatement system. The District will impose a permit condition requiring ConocoPhillips to monitor the pressure in each tank to determine whether the pressure relief valves have lifted resulting in emissions to the atmosphere. Corrective action is required if a pressure relief valve lifts 3 times in one year.

In addition, the following aspects of the project should reduce odors.

- ConocoPhillips is installing a fourth sulfur recovery unit to ensure that it has sufficient capacity to remove sulfur.
- ConocoPhillips is installing a sulfur degassing unit.
- The project will result in less shipping of heavy gas oil.

SO_2 levels may be higher than levels elsewhere in the District, but the levels are within regulatory limits meant to protect the public.

Comment 2: Franklin Canyon and one neighborhood in Rodeo will benefit from the SO_2 mitigation at the Carbon Plant. Crockett and other neighborhoods will suffer.
Response: The regulations allow for one part of a facility to provide offsets for another part of a facility, even if there is some geographical distance between the source of the emissions and the source of the offsets. In addition, ConocoPhillips has agreed to lower the proposed annual emissions of SO_2 from the sulfur recovery unit from 36.7 tons per year to 29.7 tons per year.

Comment 3: The refinery has volunteered to reduce particulate by 172 lbs/day and SO_2 by 7 tons/yr beyond that stated in the DEIR. We request that the BAAQMD permit be revised to include these additional particulate and SO_2 reductions. (An email from Phil Stern to Howard Adams of the Good Neighbor Agreement Committee containing various promises was included in this comment.)
Response: The permit for S1004, Sulfur Recovery Unit, will be modified to include a lower limit for SO_2. In regards to the reduction of 172 lb/day of particulate, the email refers to drift eliminators at the existing sulfur plant cooling tower. The District understands that the proposed drifts eliminators have already been installed and will not include them as part of this application.

Response to Air Liquide Comments

<u>Comment 1</u>: The Facility ID provided on the cover sheet of the Proposed Engineering Evaluation, B7419 is different than the ID provided in the header of the rest of the document (B7459). Air Liquide requests that the District place the proper Facility ID on all pages of the document.

<u>Response</u>: The correct number is B7419. The correction to the header has been made.

<u>Comment 2</u>: Section 2. Emissions, page 5 states :

"Air Liquide has calculated the maximum daily emissions for the flare. If the pressure swing absorption process malfunctions, up to 6.41 MMscf/hr of syngas could be sent to the flare for 4.8 hours/event. The composition of syngas is mainly hydrogen, methane, and CO, ……"

The values for maximum daily flow rate and duration for flaring events are incorrect. As reflected in Appendix A of the Proposed Engineering Evaluation for the Loss of PSA scenario, the correct values should be 7.74 MMscf/hr for the flow rate and 5.3 hours/event for the duration. Air Liquide requests that the District change the statement on page 5 to reflect the correct values for flow and duration that are provided in Appendix A.

<u>Response</u>: The correction has been made.

<u>Comment 3</u>: Section 5 Statement of Compliance, Subpart Da, page 24 states:

"Electricity will be generated at the hydrogen plant, but the output will be about 10.4 MW so S2, Hydrogen Plant Furnace, is not subject to the standard."

The actual rated capacity of the steam turbine generator is **12** MW as provided on page 3 of the Proposed Engineering Evaluation. Air Liquide requests that the District change the statement on page 24 to reflect the proper rated capacity.

<u>Response</u>: The correction has been made.

<u>Comment 4</u>: Section 5 Statement of Compliance, Monitoring Analysis, page 26 states:

"If gases are sent to the flare that are considered to be startup, shutdown, malfunction, or upset gases, the facility must monitor the gases continuously for H2S in accordance with 40 CFR 60.104."

40 CFR 60.104 establishes the standard for emissions of H2S and specifically exempts all startup, shutdown, malfunction, or upset gases. Therefore a proper reading of this condition should be: "If gases are sent to the flare that are **not** considered to be startup, shutdown, malfunction, or upset gases, the facility must monitor the gases continuously for H2S in accordance with 40 CFR 60.104." Air Liquide requests that the District make this change to be consistent with the regulatory requirement.

<u>Response</u>: The correction has been made.

<u>Comment 5</u>: Section 7 Permit Conditions, Condition 23178, #16, page 31 identifies the exact number of fugitive components to be installed. This degree of specificity is not appropriate or necessary. The exact number of valves, flanges, pumps and compressors can only be estimated at this time and this is what was provided in the permit application. The actual count of fugitive components to be determined upon completion of the project may differ from the count specified in the Proposed Engineering Evaluation. Regardless, the allowable POC emission limit of

1.5 tons/yr will not change. Air Liquide requests that the District delete the specific fugitive component count from this condition.

Response: It is the District's practice to ask for the component count to ensure that the estimated emissions are accurate. However, the District acknowledges that the number of components may change. Therefore, the following language has been added to Condition 23178, part 16: " The exact number of components may change without penalty.

Comment 6: Section 7 Permit Conditions, Condition 23179, #5, page 31 states that the emission concentration limits shall not be exceeded except during startup periods. This condition allows for a 72 hour startup when drying refractory or during the first startup following catalyst replacement. Manufacturer recommendations for startup periods when drying refractory exceed this 72 hour period. Steam methane reformers have very complex inlet and outlet systems that require a longer heat up phase. The recommended time is approximately 110 hours. Air Liquide requests a startup period when drying refractory of 120 hours to ensure a smooth and successful drying out period. Attached as Exhibit A, is an excerpt from the manufacturer's recommendations for the Hydrogen Plant commissioning. Air Liquide requests that the District change the allowable hours of startup for drying refractory from 72 hours to 120 hours.

Response: The District has made the change.

Comment 7: Section 7 Permit Conditions, Condition 23179, # 7a, page 32 states that the hourly mass emission limits shall not be exceeded except during startup periods. As in Comment 6, Air Liquide requests that the startup period when drying refractory be changed from 72 hours to 120 hours.

Response: The District has made the change.

Comment 8: Section 7 Permit Conditions, Condition 23180, # 2, page 36 states:

'The owner/operator shall ensure that S3, Hydrogen Plant Flare, is only used during startup, shutdown, upset, or malfunction of S1, Hydrogen Plant."

Other operating conditions can cause gases to be sent to the flare and are included in the overall emissions estimate for this source. These include customer constraint, loss of PSA, PSA maintenance and contractual outage and are included in Appendix A of the Proposed Engineering Evaluation. Air Liquide requests that the District change this condition to include the operating scenarios of 'customer constraint, loss of PSA, PSA maintenance and contractual outage'.

Response: The District has made the correction. The application documents included this scenario. Please note, however, that this change in condition will mean that H2S must be monitored continuously in accordance with 40 CFR 60, Subpart J. Part 12, which requires the monitor, has been added to the condition. If USEPA removes the requirement for monitoring in its revisions of the standard, which are due in April of 2008, the monitor will not have to be installed.

Comment 9: Section 7 Permit Conditions, Condition 23181, B. Project Mass Emission Limits, # 4 d and e, page 38 specifies the source of the monitoring data to be used to determine compliance with the annual mass emission limits. Items # 4 d and e specify the use of monitoring data for total sulfur in the feed to the hydrogen plant and hydrogen plant furnace respectively. As allowed by Condition 23179, # 14b, the owner/operator may install a SO2 CEM in lieu of a sulfur analyzer for the feed gases. In this case, the source of data for determining compliance with the annual mass emission limit for SO2 should be the SO2 CEM system. Air Liquide requests that the District change this condition to include the alternative of using CEM data to determine compliance with the annual mass emission limit for SO2.

Response: The District has made the change. In this case, SO_2 monitoring at the stack may be more convenient than H_2S monitoring for several input streams.

Comment 10: Section 7 Permit Conditions, Condition 23414, page 40. The numbering sequence for the items in Condition 23414 is incorrect. The sequence numbers for 6 and 7 are repeated twice. The last two items should be changed to item numbers 8 and 9. Air Liquide requests that the District change the numbering sequence in Condition 23414.

Response: The District has made the correction.

Response to ConocoPhillips Comments

<u>Comment 1</u>: Increase the PM10 reduction at Kiln 2 (S2) from 7.5 tons per year to 8.0 tons per year. This will change the proposed PM10 limit from 29.90 to 29.40 tons per year.
<u>Response</u>: The PM10 limit will be lowered to 29.4 tons per year.

<u>Comment 2</u>: Reorganize the permit condition for S1007, DAF, for clarity. See attached strikeout version.
<u>Response</u>: The District agrees to reorganize the condition.

<u>Comment 3</u>: Add clarification to the permit conditions for S45, Heater, to better differentiate between testing conducted by the owner/operator versus BAAQMD testing. The clarification was accomplished primarily by reorganizing the permit condition. See attached strikeout version.
<u>Response</u>: The District agrees that the facility may use tests performed by the District, if the District performs tests. The requested clarification has been added.

<u>Comment 4</u>: Change wording on condition regarding PRDs at process units.
<u>Response</u>: The applicant has agreed that no changes are necessary.

<u>Comment 5</u>: ConocoPhillips is strongly opposed to the requirement for rupture discs on PRDs as a component of the BACT requirements.
<u>Response</u>: The refinery has made a strong case against the use of rupture discs on PRDs. Rupture discs can fail in an environment of varying temperatures and pressures and the fragments may cause an equipment malfunction. The purpose of rupture discs is to enable a person to tell whether a PRD has opened, resulting in flow of gases to a relief system or to atmosphere. ConocoPhillips has argued that the process equipment has sufficient pressure monitoring devices that they can tell if a PRD in a piece of equipment has opened. Therefore, the rupture discs are not necessary.

BACT also requires routing of all new PRDs to a "fuel gas recovery system, furnace or flare with a recovery/destruction efficiency of 98%." All new PRDs in this project will be routed to the flare gas recovery system, which routinely recovers emissions from the PRDs, compresses them, and routes them to the fuel gas system. These events will not cause additional emissions unless an event results in flaring.

ConocoPhillips is obligated to prepare a causal analysis pursuant to BAAQMD Regulation 12-12-406 for any flaring over 500,000 cubic feet/day or over 500 lb SO2/day. During the investigation for the causal analysis, ConocoPhillips must determine the cause of flaring. As part of the cause determination process pressure data is examined to determine the source of flow, especially during periods when a relief valve routed to the flare is suspected of relieving to the fuel gas and/or flare system. Therefore, the rupture discs are not necessary.

<u>Comment 6</u>: Allow the exclusion of emissions associated with incidents where breakdown relief or a variance has been granted.
<u>Response</u>: BAAQMD Condition 22970, part A, is the "bubble" condition that ensures that the project's annual emissions will not exceed the amount for which ConocoPhillips has applied. ConocoPhillips estimated that very few emissions would be caused by venting of the new cracking unit, S434, to the flare due to the vessel's high pressure rating; and estimated that no emissions would caused by the venting of the new sulfur recovery unit, S1004, to the flare because the refinery has redundant sulfur recovery systems. Instead, the facility has asserted that that any emissions during startup, shutdown, upsets, or malfunctions would be compensated for with normal shutdown periods, and that therefore the annual limits were sufficient.

The District believes that emissions during startup, shutdown, upsets, or malfunctions can be predicted. ConocoPhillips has ample experience with units such as the units that ConocoPhillips is proposing to build. District and federal PSD and NSR regulations do not have provisions that state that emissions during startup, shutdown, upsets, or malfunctions are "free." In 40 CFR 51.165(a)(1)(xxviii)(B), EPA includes the following in the definition of "Projected actual emissions":

(2) Shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions; …

Other permits for projects of this size have fairly comprehensive startup, shutdown, commissioning, upset, and malfunction conditions that allot a certain amount of emissions for each type of situation and include rigorous recordkeeping. In exchange for the District not imposing these conditions and for not requiring a forecast of the emissions during these situations, ConocoPhillips has agreed to firm annual limits. Excluding emissions from the annual limit because breakdown relief or a variance has been granted would make a "bubble" condition invalid; therefore the District cannot make the change. The applicant is invited to propose alternate startup, shutdown, upset, malfunction, and commissioning conditions with appropriate emissions estimates, accompanied by a concomitant reduction in normal operating conditions, to replace the "bubble" condition before the permit is finalized.

Comment 7: Specifically list the sources of contemporaneous emissions in PC 22790 for clarity. See attached strikeout version.
Response: BAAQMD Condition 22790, part B, addresses the deadlines for providing contemporaneous offsets in accordance with BAAQMD Regulation 2-2-410 and requires a quarterly report until all of the necessary credits have been provided. It is appropriate to list the sources of the offsets, so the District agrees to include them in the condition.

Comment 8: Revise the applicability timing language in condition 1440, part 7, for consistency with PC 22970 Part B and clarity. See attached strikeout version.
Response: BAAQMD Condition 1440, part 7, requires control of emissions from S1007, Dissolved Air Flotation Unit, to provide POC offsets for the CFEP project. The language regarding the deadline for provision of the offsets has been revised for clarity and consistency with BAAQMD Condition 22970, Part B.

Comment 9: Revise the applicability timing language for consistency with PC 22970 Part B and clarity. Change the first sentence of PC 12122-9b to the following: "This part will apply after NOx emissions at S352, S353, S354, S355, S356 and S357 must be reduced to provide offsets for Application 13424 **per Condition 22970 Part B."**
Response: BAAQMD Condition 12122, part 9b, requires control of emissions from S352, S353, S354, S355, S356 and S357, Turbines and Duct Burners, to provide NOx offsets for the CFEP project. The language regarding the deadline for provision of the offsets has been revised for clarity and consistency with BAAQMD Condition 22970, Part B.

Comment 10: Change the frequency of throughput recordkeeping from "monthly" to "daily" to provide consistency with Conditions 22965 and 22966.
Response: The frequency of throughput recordkeeping at S309, Unisar Unit, has been changed from monthly to daily.

ATTACHMENT 5

CEQA Findings

CONOCOPHILLIPS – SAN FRANCISCO REFINERY
PROPOSED CLEAN FUELS EXPANSION PROJECT

FINDINGS AND SUPPORTING FACTS REGARDING THE ENVIRONMENTAL IMPACT REPORT

ConocoPhillips - San Francisco Refinery (The Refinery) has proposed to construct the Clean Fuels Expansion Project (CFEP) at its Rodeo Refinery. The CFEP includes new equipment and modifications to existing equipment that would enable the Refinery to process heavy gas oil (HGO), which is a by-product that is currently produced onsite and exported. Implementation of the CFEP would allow overall Refinery production to increase by up to 1,000,000 gallons per day (30 percent over current levels).

The CFEP includes the following: (1) construction of a new Hydrogen Plant to be built by Air Liquide with a capacity of 120 million standard cubic feet per day; (2) construction of a new Sulfur Recovery Unit with a capacity increase of 200 long tons per day; (3) conversion of a retired lube oil rail car loading rack into a butane rail car loading rack; (4) expansion of the Unicracker to allow for HGO hydrocracking and resulting in an increase in capacity of 23,000 barrels per day (bbl/day); (5) Reformer (Unit 244) modifications resulting in a capacity increase from 16,087 bbl/day to 18,500 bbl/day; (6) UNISAR (Unit 248) modifications resulting in a capacity increase from 8,812 bbl/day to 16,740 bbl/day; (7) Product Blending Unit (Unit 76) modifications resulting in a capacity increase from 90,411 bbl/day to 113,150 bbl/day; (8) Deisobutanizer (Unit 215 DIB) modifications resulting in a capacity increase from 7,600 bbl/day to 10,200 bbl/day; (9) Sulfur Recovery Plant (Units 234, 236, 238) modifications that would include a new sulfur degassing system, a new sulfur loading rack, a modified or replaced amine regenerator and an increase in sulfur storage capacity; and (10) modifications to ancillary facilities such as pumps, heat exchangers, instrumentation, utilities and piping.

Contra Costa County Community Development Department (CDD) acted as Lead Agency under the California Environmental Quality Act (CEQA) for this project. As a responsible agency under CEQA, the Bay Area Air Quality Management District (BAAQMD) participated in the EIR process, including reviewing and commenting on the Draft EIR. The following timeline illustrates the land use permit application's progress from approval by County Planning Commission (CPC) to present:

- April 24, 2007 – Public hearing held before the CDD in Martinez to consider certification of the Final EIR and approval of the CFEP.

- May 8, 2007 – Second CPC hearing held in Martinez. Final EIR was certified and project was approved with new and modified Conditions of Approval.

- May 17, 2007 – Appeal received from Communities for a Better Environment and Center for Biological Diversity (CBE/CBD), joint appellants.

- May 18, 2007 – Appeal received from ConocoPhillips Company and appeal received from the California State Attorney General.

- September 10, 2007 – California Attorney General withdrew his May 18, 2007 appeal and submits a copy of Settlement Agreement with ConocoPhillips Company. Concurrently, ConocoPhillips requests that the County include language from the Settlement Agreement in the County's action on its appeal.

- September 25, 2007 – Board of Supervisors hearing held in Martinez. Final EIR was certified and project was approved. Board accepted the September 10, 2007 letter from the California Attorney General withdrawing their May 18, 2007 appeal. The Board denied the appeals of Communities for a Better Environment (CBE) and Center for Biological Diversity (CBD). The Board also granted the appeal of ConocoPhillips Company based on their revised proposed condition of approval addressing the storage of rail cars.

The EIR identified certain potentially significant environmental impacts that could occur as a result of the CFEP. The following discussion summarizes the air quality related effects identified in the EIR and during the District's review of the ConocoPhillips and Air Liquide permit applications, makes one or more of the findings required under Section 15091 of the State CEQA Guidelines, and presents facts to support the findings. All of these effects have been mitigated to a level of insignificance.

<u>Impact 1</u> – Construction activities associated with CFEP would generate short-term emissions of criteria pollutants, including suspended and respirable particulate matter and equipment exhaust emissions, which would contribute to existing air quality violations.

Mitigated to insignificance. Particulate emissions will be mitigated by implementation of comprehensive dust control measures including watering all active construction areas at least twice daily; covering of haul trucks or requiring all trucks to maintain at least two feet of freeboard; paving or otherwise stabilizing haul roads, parking and staging areas; and sweeping daily with water sweepers all paved access roads, parking areas and staging areas at construction sites. The following "enhanced" control measures will also be implemented: Hydroseeding or application of non-toxic soil stabilizers to inactive construction areas; enclosing, covering, watering twice daily or application of non-toxic soil binders to exposed stockpiles; installation of sandbags or other erosion control measures to prevent silt runoff to public roadways; suspension of excavation and grading activity when winds exceed 25 mph; installation of wheel washers for all exiting trucks, or washing off the tires or tracks of all trucks and equipment leaving the site.

Equipment emissions will be mitigated by regular equipment maintenance and limits to unnecessary idling. Other equipment mitigation measures include the following: use of alternative fuels and/or alternatively fueled equipment; use of post-1996 model diesel trucks only at the site or for on-road hauling of construction material; requirement for all construction diesel engines with a rating of 100 hp or more to meet at a minimum the Tier 2 California Emission Standards for Off-Road Compression –Ignition Engines unless certified by the onsite Construction Air Quality Mitigation Manager (CAQMM) that such an engine is not available for a particular item of equipment; offering incentives to encourage construction workers to carpool or employ other means of transportation; scheduling construction activities to allow at least 33% of the construction workforce to avoid the morning and afternoon peak traffic periods; and use of on-site power to minimize reliance on portable generators.

Impact 2 – Operational activities associated with the implementation of the CFEP would increase air pollutant emissions, contributing to existing air quality violations.

Mitigated to insignificance. As required by BAAQMD Rules and Regulations, project emissions will be mitigated by application of Best Available Control Technology (BACT) and by obtaining emission offsets. Specifically, following mitigation measures will be implemented:

- The four Dissolved Air Flotation (DAF) vents associated with the onsite wastewater treatment plant will be routed to a Thermal Oxidizer with a destruction efficiency of no less than 98 percent. The DAF outlet channel and downstream sumps will be sealed by a solid cover with gaskets. Any vents installed on the covered channel will be routed to the thermal oxidizer. Installation of these controls will reduce organic emissions by at least 242 pounds per day and 44.1 tons per year.

- The Refinery Steam Power Plant uses three gas turbines to generate electricity, and uses gas turbine waste heat to generate steam. Each gas turbine has a nitrogen oxide (NOx) catalyst system located at the base of the exhaust stack. The Refinery will take a new permit limit to achieve a reduction of NOx concentration in each stack by 1 ppm from its current operating baseline. This 1 ppm of NOx equates to a reduction of 81 pounds per day and 14.7 tons per year.

- Operations at the ConocoPhillips' Carbon Plant will be modified to result in a decrease in SO2 emissions of at least 230 pounds per day and 42 tons per year. The refinery will take a new permit limit to reflect this reduction.

- The baghouse at the Carbon Plant will use improved bag technology to capture particulate matter (PM_{10}) from the calcined coke operation. Installation of the improved bag-technology will reduce PM_{10} emissions by at least 43.8 pounds per day and 8.0 tons per year. The refinery will take a new permit limit to reflect this reduction.

- Net reductions in ROG emissions associated with the mitigated CFEP will be used to offset 36 pounds per day and 7.6 tons per year of NOx associated with the CFEP.

Impact 3 – The CFEP would contribute to cumulative regional air emissions; however, it would not be cumulatively considerable and it would not conflict with or obstruct implementation of the applicable air quality plan.

Mitigated to insignificance. As discussed in Impact 2, with the proposed mitigation measures, the CFEP would have a less-than-significant impact on air quality. Furthermore, as discussed in Section 4.10, Land Use, in Final EIR, the CFEP is consistent with the Contra Costa County General Plan which in turn is consistent with the BAAQMD's current air quality plan (2005 Ozone Strategy).

Impact 4 – Operational activities associated with the implementation of the CFEP could lead to increases in odorous emissions. This would be a less-than-significant impact.

No mitigation required. The CFEP will not result in increased odors because the hydrocracking process that would be used to process heavy gas oil produces clean intermediate feedstocks and blendstocks. Storing these products in existing tanks will not increase odors. Also, CFEP contains numerous design features that will reduce odor emissions from existing equipment and minimize the likelihood of odor emissions from the project's new equipment. CFEP-related design features include the following:

- A fourth compressor will be added to the odor abatement system. This will increase the robustness of the odor control system. The new compressor will be sized at approximately 3.3 MMSCFD and is slated to commence operation in March 2009.

- The new compressor will primarily be loaded with odor abatement gases but will be operated so that during most periods, it can pick up the swings that occur during brief peak loading on the existing G-503, Flare Gas Recovery (FGR) compressor. This new compressor will also be used to mitigate flaring when the G-503 FGR compressor is down for planned or emergency maintenance. This additional flare gas recovery capacity will further reduce odor-causing flaring.

- The vapor recovery will be installed on existing fixed-roof tanks that will change service to store heavy gas oil and sour water.

- The Odor abatement system will be subject to new and more stringent permit conditions by the BAAQMD to eliminate and/or minimize odor complaints.

- A new sulfur recovery unit will increase system redundancy and improve the refinery's ability to react to upset conditions for processing sulfur gases. This will reduce the number of refinery upsets and shutdowns.

- Molten sulfur loaded into trucks will be degassed prior to loading, which will reduce the H_2S emissions.

- The Dissolved Air Flotation unit at the wastewater treatment plant will be vented to a thermal oxidizer.

- After startup of the CFEP, less heavy gas oil will be loaded onto barges, which vent to the atmosphere.

As required by the State CEQA Guidelines, the BAAQMD, as a Responsible Agency for the ConocoPhillips CFEP, hereby finds that, for each of the impacts identified in the final EIR and discussed above, changes or alterations have been required in, or incorporated into, the project which avoid or substantially lessen the significant environmental effect as identified in the final EIR. In addition, for those mitigation measures that are identified in the final EIR to lessen impacts associated with construction activities and vehicle emissions and that are within the responsibility or jurisdiction of another public agency, the BAAQMD hereby finds that such measures either have been or can and should be adopted by such other agency.

In accordance with BAAQMD Rules and Regulations, the BAAQMD has fully considered the EIR prepared and certified by the Contra Costa County and has incorporated the EIR's analysis into its decision-making process. The BAAQMD granted an Authority to Construct for the proposed project on October 5, 2007.

The documents and other materials that constitute the record of proceedings upon which this decisions is based are located at the BAAQMD office at 939 Ellis Street, San Francisco, California, and the custodian of the materials is Rochelle Henderson.

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Jack P. Broadbent
Executive Officer/Air Pollution Control Officer
Bay Area Air Quality Management District

APPENDIX C

Engineering Evaluation Application 13424

FINAL
BAY AREA AIR QUALITY MANAGEMENT DISTRICT
ENGINEERING EVALUATION
CONOCOPHILLIPS SAN FRANCISCO REFINERY; PLANT 16
APPLICATION NO. 13424

October 5, 2007

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1. BACKGROUND

ConocoPhillips has submitted an application entitled "Clean Fuel Expansion Project " (CFEP). The purpose of the CFEP is to process heavy gas oil (HGO) that is produced at the coker crude unit, coker, and pre-fractionator, and that is received from the Santa Maria refinery via pipeline into gasoline and diesel. In order to do this, ConocoPhillips will add a high-pressure reactor train to S307, Unicracker. The new train will be integrated into S307, but will have a new source number, S434. ConocoPhillips will also increase the permitted capacity of S307, Unicracker; S309, Unisar; S432, Deisobutanizer; and S308, Reforming Unit. S1004, a new 200 long ton/day sulfur recovery unit (SRU), will be built. The new SRU will be designed without oxygen enrichment. A new 85 MMbtu/hr heater, S45, will be added for S434. The service will change on the following tanks: S98, S123, and S124. Tanks S118, S122, S128, S139, S140, and S182 will have throughput changes. S98 will switch from exempt diesel service to petroleum fluids with a vapor pressure up to 10 psia. The allowable vapor pressures at S123 and S124 will increase to 3.0 psia and 11.0 psia, respectively.

ConocoPhillips needs more hydrogen than it can currently produce to process the heavy gas oil. Air Liquide will build a new hydrogen plant on site and will retain ownership of the plant and operate it. However, ConocoPhillips will use all of the facility's output. BAAQMD Regulation 2-1-213 defines facility as:

> "Any property, building, structure or installation (or any aggregation of facilities) located on one or more contiguous or adjacent properties and under common ownership or control of the same person…"

The hydrogen plant will be on ConocoPhillips property, so it meets the conditions of "contiguous or adjacent." In addition, the hydrogen plant will take its feed from the refinery. ConocoPhillips will direct the hydrogen plant to produce the amount of hydrogen that it needs at any time, so the hydrogen plant is considered to be under ConocoPhillips' control. Therefore, the hydrogen plant will be considered to be part of the refinery. The hydrogen plant will also supply steam and electricity to ConocoPhillips.

Since it is part of the refinery, the two projects (CFEP and hydrogen plant) will be considered as one project for the purposes of NSR, PSD, Major Facility Review (Title V), offsets, NSPS, NESHAPS, and any other applicable requirements.

The Title V regulations in 40 CFR 70 allow agencies to issue more than one Title V permit to a facility. Because the hydrogen plant will be owned and operated by Air Liquide, it will have a separate plant number, B7419, and a separate application, No. 13678.

The ConocoPhillips Carbon Plant, Plant A0022, is owned and operated by ConocoPhillips. It is contiguous to the refinery. Although it has a separate plant number and Title V permit, it is also considered part of the ConocoPhillips facility. The applicant will reduce emissions at the carbon plant to obtain reductions in actual emissions of PM10 for the purposes of CEQA and contemporaneous offsets of SO2.

The facility will also generate contemporaneous offsets at the refinery by permanently reducing emissions of POC at S1007, Dissolved Air Flotation Unit; permanently reducing emissions of combustion contaminants by shutting down S8, Boiler; and permanently reducing NOx emissions at the Steam Power Plant, S352-S357.

The list of equipment that is affected at ConocoPhillips, Facility A0016, is shown below:

- S45, Heater (U246), 85 MMbtu/hr
- S98, Tank 101, EFRT, 170k barrels
- S118, Tank No. 163, fixed roof, 5.3k barrels
- S122, Tank No. 167, EFRT, 3.1 MMgals
- S123, Tank No. 168, EFRT, 75k barrels
- S124, Tank No. 169, EFRT, 75k barrels
- S128, Tank No. 174, EFRT, 76k barrels
- S139, Tank No. 204, fixed roof, 81k barrels, abated by A7, Vapor Recovery System
- S140, Tank No. 205, fixed roof, 54k barrels, abated by A7, Vapor Recovery System
- S168, Tank No. 269, fixed roof, 39k barrels, abated by A7, Vapor Recovery System
- S173, Tank No. 280 fixed roof, 134k barrels, abated by A7, Vapor Recovery System
- S174, (Tank No. 281), fixed roof, 134k barrels, abated by A7, Vapor Recovery System
- S182, Tank No. 294, fixed roof, 40k barrels, abated by A7, Vapor Recovery System
- S465, Sulfur Pit 235 abated by S1004, U235 Sulfur Recovery Unit
- S307, U240 Unicracking Unit (increase of 23,000 bbl/day)
- S308, U244 Reforming Unit (increase of 2,413 bbl/day)
- S309, U248 UNISAR Unit (increase of 7,830 bbl/day)
- S318, U76 Gasoline Blending (increase of 8,300,000 bbl/yr)
- S339, U80 Gasoline/Mid Barrel Blending
- S352, Combustion Turbine
- S353, Combustion Turbine
- S354, Combustion Turbine
- S355, Duct Burner
- S356, Duct Burner
- S357, Duct Burner

S432, U215 Deisobutanizer (increase of 2,600 bbl/day)
S434, U246 High Pressure Reactor Train (Cracking) (23,000 bbl/day)
S464, Hydrogen Plant (not new source, was originally permitted as part of S307, U240 Unicracking Unit)
S503, Sulfur Storage Tank abated by S1004, U235 Sulfur Recovery Unit
S504, Sulfur Degassing Unit abated by S1004, U235 Sulfur Recovery Unit
S505, Sulfur Truck Loading Rack abated by S1004, U235 Sulfur Recovery Unit
S1004, U235 Sulfur Recovery Unit (200 long tons/day)
S1007, Dissolved Air Flotation Unit (DAF)
A7, Odor Abatement System
A47, SCR abating S45, Heater
A48, SRU Tail Gas Treatment Unit abating S1004, Sulfur Recovery Unit
A49, DAF Thermal Oxidizer (440,000 btu/hr) abating S1007, Dissolved Air Flotation
A51, DAF Carbon Bed
A424, Tail Gas Incinerator abating A48, SRU Tail Gas Treatment Unit and S1004, Sulfur Recovery Unit

Demolitions
S8, Boiler, U240 B-1 Boiler, 256 MMbtu/hr

Sources S45, S465, S434, and S1004, and abatement devices A47, A48, A49, and A424 will be new.

The list of equipment that is affected at ConocoPhillips, Plant A0022, is shown below:
S2, K-2, Kiln Burner

The list of new equipment for Air Liquide, Plant B7419, is shown below:
S1, Hydrogen Plant including HRSG and steam turbine generator (10.5 MW)
S2, Hydrogen Plant Furnace, 1,072 MMbtu/hr abated by A1, SCR
S3, Hydrogen Plant Flare, 2200 MMbtu/hr
S4, Cooling Tower, 3,700 gpm
S5, Ammonia Tank, 10,000 gal

The application states that emissions from ships and barges will decrease because the most of the HGO that will be processed in the new unicracker, S434, will not be shipped through the marine loading source. Some is being produced at the refinery now and some will be shipped up from the Santa Maria refinery via the pipeline. Currently, an average of 249,000 barrels per year of HGO destined for S305, Prefractionator, is shipped to the refinery via marine vessels. This HGO will be sent to the new Hydrocracker, S434, after being processed at S305.

The emissions increase in vessels carrying gasoline will be smaller than the decrease caused by processing the HGO that is in-house. ConocoPhillips has a firm limit on the amount of gasoline that can be shipped via ship or barge. The increase in heavy gas oil that is received from the Santa Maria refinery will be received by pipeline, not ship or barge, per the applicant. Also, a permit condition will be imposed on the marine loading source to restrict the amount of HGO received for this purpose via the marine loading source to 249,000 barrels per year.

2. EMISSION CALCULATIONS

The emissions are calculated in different ways to determine applicability of various requirements. The emission calculations will be presented in this order:

Actual and CEQA emissions
Emission calculations for the purposes of offsets
PSD emissions

2.1 Actual and CEQA emissions

The detailed emission calculations of criteria pollutants (NOX, SO2, PM10, POC, and CO) are in Appendix A. Following is a summary of the proposed emissions in tons per year from the changes to the ConocoPhillips plant.

After the public comment period, the facility agreed to lower the NOx and CO emissions at S45, Heater, and the SO2 emissions at S1004, Sulfur Recovery Unit. The facility also agreed to lower the overall emission limit for PM10 by 0.2 ton/yr.

	Tons per Year				
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**
S45, New Unit 246 HGO Feed Heater[1,4]	2.3	4.7	1.9	1.5	2.8
S434, New Unit 246 Startup/Shutdown[2]	<0.01	<0.01	-	0.03	0.02
S1004, New SRU (Unit 235)	11.2	29.7	0.59	0.4	37.9
Tanks 101, 168 & 169 Permit Cond. Change				8.1	
Existing Tanks				4.8	
Fugitives				6.1	
Paved Roads			1.1		
S8, Unit 240 Boiler B-1 Reductions[1]	-22.4		-2.9	-2.1	-43.4
Increased Heater Utilization[2]	7.2	1.2	3.1	2.3	2.8
Increased Tank Utilization[2]				1.0	
Refinery Steam Power Plant Reductions	-22.1				
Locomotive Emissions	2.2	0.2	0.08	0.1	0.3
Truck and Commuter Auto Trips[3]	2.2	<0.1	0.1	0.2	2.7
S1007, Dissolved Air Flotation (DAF) Unit	0.2	1.2	0.01	-44.1	0.2

	Tons per Year				
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**
Butane Loading Rack[3]				0.2	
Total	**-19.2**	**37**	**4.0**	**-21.5**	**3.3**

[1] CEQA does not require emissions to be RACT-adjusted.
[2] Increases within permitted limits
[3] Exempt source
[4]S45 and S1004 together will emit less than 2.5 tpy PM10. Reduction shown here at S45 for convenience.

Following is a summary of the original proposed emissions in tons per year from the proposed Air Liquide hydrogen plant. The annual emissions were calculated for the average operating rate of 975 MMbtu/hr. The maximum daily emissions were calculated for the maximum operating rate of 1,072 MMbtu/hr.

Summary of Hydrogen Plant Emissions

	Tons per Year					
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**	
New SMR Furnace	28.1	5.0	15.8	11.5	34.2	(975 MMBtu/hr, annual average)
Deaerator Vent	--	--	--	0.8	--	
Flare Pilots/NG Purge	0.12	0.004	--	--	1.1	
Startup/Shutdown	2.7	0	0	0.1	11	
Cooling Tower			0.5	1.5		
Fugitives	--	--	--	1.5	--	
Total	30.9	5.0	16.3	15.4	46.2	

	Lb per Day					
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**	
New SMR Furnace	169	30	95	69	206	(1072 MMBtu/hr, hourly maximum)
Deaerator Vent	--	--	--	4.4	--	
Flare Pilots/NG Purge	0.68	0.022	--	--	5.9	
Cooling Tower			2.5	8.2		
Fugitives	--	--	--	7.9	--	
Total	170	30	97.5	90.2	212	

Air Liquide's final proposal is to reduce the particulate emissions from the new SMR furnace to 13.8 tons per year. Air Liquide may comply by showing that the particulate emission factor is less than 0.0037 lb/MMbtu or by curtailing operations. The resulting annual emissions are:

Summary of Hydrogen Plant Annual Emissions

	Tons per Year				
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**
New SMR Furnace	28.1	5.0	13.8	11.5	34.2
Deaerator Vent	--	--	--	0.8	--
Flare Pilots/NG Purge	0.12	0.004	--	--	1.1
Startup/Shutdown	2.7	0	0	0.1	11
Cooling Tower			0.5	1.5	
Fugitives	--	--	--	1.5	--
Total	30.9	5.0	14.3	15.4	46.2

Following is a summary of the proposed emission reductions in tons per year from the ConocoPhillips carbon plant, Plant A0022. The SO2 reductions are considered ERCs that comply with BAAQMD Regulation 2-2-201. The PM10 reductions do not comply and will be accepted for the purposes of CEQA only, which does not require RACT reductions for ERCs.

SO2: 42 tons per year
PM10: 8 tons per year

(Note: The PM10 reduction was increased from 7.5 to 8 tons per year.)

The total actual and CEQA emissions increases from the project are:

	Tons per Year				
	NOx	**SO2**	**PM10**	**POC**	**CO**
ConocoPhillips Refinery	-19.2	37	4.0	-21.5	3.3
Hydrogen Plant	30.9	5.0	14.3	15.5	46.2
ConocoPhillips Carbon Plant		-42.0	-8		
Total	11.7	0	10.3	-6.0	49.5

2.2 Emissions for the purposes of cumulative increase and offsets

The PM10 emission reductions at the Carbon Plant are not considered ERCs for the purposes of BAAQMD Regulation 2-2-201 because these reductions are not "in excess of the reductions achieved by, or achievable by, the source using Reasonably Available Control Technology." The last three source tests show that the emission rate is approximately 0.04 gr/dscf. RACT has not been determined, but is estimated to be 0.01 or 0.02 gr/dscf.

For the refinery, the following adjustments are made to the sum of actual emissions in the first table in Section 2.1. The NOx reduction for S8 has been RACT-adjusted to 16.7 based on the RACT level of 0.033 lb/MMbtu in BAAQMD Regulation 9, Rule 10. The increased heater and tank utilization were not included since they are within permitted limits. The truck and commuter trips and the butane loading rack increases are not included since they do not require permits.

After public notice, the emissions estimates for NOx and CO at S45, Heater, have been reduced due to a new BACT determination and the facility has agreed to lower the annual SO2 emissions at S1004, Sulfur Recovery Unit, in response to a public comment.

	Tons per Year				
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**
S45, New Unit 246 HGO Feed Heater[1, 4]	2.3	4.7	1.9	1.5	2.8
S434, New Unit 246 Startup/Shutdown[2]	<0.01	<0.01	-	0.03	0.02
S1004, New SRU (Unit 235)	11.2	26.7	0.59	0.4	37.9
Tanks 101, 168 & 169 Permit Cond. Change				8.1	
Existing Tanks				4.8	
Fugitives				6.1	
Paved Roads			1.1		
S8, Unit 240 Boiler B-1 Reductions	-16.7		-2.9	-2.1	-43.4
Refinery Steam Power Plant Reductions	-22.1				
Locomotive Emissions	2.2	0.2	0.08	0.1	0.3
S1007, Dissolved Air Flotation (DAF) Unit	0.2	1.2	0.01	-44.1	0.2
Total	**-22.9**	**32.8 .**	**0.78**	**-25.1**	**-2.2**

(Note: The sum of particulate emissions in the original proposal was in error. The correct sum was 0.98 tons per year.)

The emission reductions are acceptable for the purposes of CEQA without the "RACT" adjustment. The emissions for the purposes of cumulative increase and offsets are:

	Tons per Year				
	NOx	**SO2**	**PM10**	**POC**	**CO**
ConocoPhillips Refinery	-22.9	32.8	0.8	-25.1	-2.2
Hydrogen Plant	30.9	5.0	13.8	13.9	46.2
ConocoPhillips Carbon Plant		-42.0			
Total	8.0		14.6	-11.2	

		-4.2			44

In accordance with BAAQMD Regulation 2-2-215, emissions from cargo carriers are included in the total emissions that are subject to offsets. The total above includes the emissions increase from locomotives.

2.3 Emissions for the purposes of Prevention of Significant Deterioration (PSD)

As originally proposed, this project was subject to PSD because:

- The facility is a major facility.
- The project was a major modification because the applicants were proposing an increase of 16.9 tons PM10/year.

However, ConocoPhillips and Air Liquide have decided to limit the particulate emissions from S45, Heater; S1004, Sulfur Recovery Unit; and S2, Hydrogen Plant Furnace so that the emissions for the purposes of PSD are 14.5 tons per year.

The original emission estimates for the purposes of PSD were:

	Tons per Year				
	NOx	**SO2**	**PM10**	**POC**	**CO**
ConocoPhillips Refinery[1]	-24.2	42.6	1.02	-25	2.5
Hydrogen Plant	30.9	5.0	15.8	13.9	46.2
ConocoPhillips Carbon Plant		-42.0			
Total	6.7	5.6	16.82	-11.1	48.7

[1]Locomotives are not included in the PSD total.

The final emission limits are:

	Tons per Year				
	NOx	**SO2**	**PM10**	**POC**	**CO**
ConocoPhillips Refinery[1]	-25.1	35.6	0.7	-25	-2.5
Hydrogen Plant	30.9	5.0	13.8	13.9	46.2
ConocoPhillips Carbon Plant		-42.0			
Total	5.8	-1.4	14.5	-11.1	43.7

[1]Locomotives are not included in the PSD total.

This project is not a major modification because the emission increase of PM10 is less than 15 ton per year, the emissions increases for NOx, SO2, and POC are less than 40 tons per year, and the emissions increase for CO is less than 100 tons per year. So, this project is not subject to PSD for NOx, SO2, CO, PM10, and POC. Nonetheless, modeling has been submitted for both NOx and PM10.

Following is a summary of the emissions of non-criteria pollutants found in BAAQMD Regulation 2-2-306 and 40 CFR 51.166 and the thresholds that require PSD analysis.

The ConocoPhillips refinery is a major facility for all 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 has been performed for these pollutants:

POLLUTANT	**ANNUAL AVERAGE LIMIT (TON/YR)**	**EMISSION (TON/YR)**	**DAILY LIMIT (LB/DAY)**	**EMISSION (LB/DAY)**
Lead	0.6	0.026	3.2	0.141
Asbestos	0.007	0	0.04	*0*
Beryllium	0.0004	0	0.002	0
Mercury	0.1	0.00009	0.5	0.0052
Fluorides	3	0	16	0
Sulfuric acid mist	7	6.64	38	36.4
Hydrogen sulfide	10	1.1	55	5.34
Total reduced sulfur including hydrogen sulfide	10	1.1 (note 1)	55	5.34 (note 1)
Reduced sulfur compounds including hydrogen sulfide	10	1.1 (note 1)	55	5.34 (note 1)

Note 1. 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 no emission increase for untreated or unreacted reduced sulfur compounds at combustion sources. However, the facility will be required to test for reduced sulfur compounds at the sulfur recovery unit to confirm that all reduced sulfur compounds are incinerated.

The estimates for sulfuric acid mist are close to the PSD thresholds, but they have been estimated conservatively. The estimate for the acid mist at the new SRU is based on source tests for acid mist at the 3 existing SRUs. The estimate for increased acid mist at the combustion sources is based on 5% conversion of SO2 to SO3, and all SO3 converted to H2SO4.

The facility will have an annual limit on sulfuric acid mist at the SRU, which is estimated to emit a maximum of 5.65 tpy, and will be required to perform an annual source test to show compliance.

The facility has agreed to a reduction in SO2 emissions at the SRU from 36.7 tons to 29.7 tons per year. Although the sulfuric acid mist limit has not been lowered, it is expected that the amount of sulfuric acid mist produced will decrease, because sulfuric acid mist is proportional to SO2.

The acid mist calculations are shown in Appendix B.

No PSD analysis has been performed for the specified non-criteria pollutants, but a Health Risk Screening Analysis has been completed to comply with BAAQMD Regulation 2, Rule 5, New Source Review for Toxic Air Contaminants.

2.4 Increases in toxic air contaminants

Following is a summary of the increases in toxic air contaminants at the refinery:

Substance	Emissions, lb/yr	BAAQMD Trigger Level, lb/yr
Acenaphthene	2.12E-03	
Acenaphthylene	1.39E-03	
Acetaldehyde	1.38E+01	6.40E+01
Acrolein	0.00E+00	2.30E+00
Ammonia	1.27+04	7.70E+03
Antimony	4.65E-01	7.70E+00
Arsenic	**7.64E-01**	1.20E-02
Benzene	**3.83E+02**	6.40E+00
Benzo(a)anthracene	2.89E-02	0.011*
Benzo(a)pyrene	8.06E-02	0.011*
Benzo(b)fluoranthene	3.63E-02	0.011*
Benzo(k)fluoranthene	2.17E-02	0.011*
Cadmium	**8.88E-01**	4.50E-02
Chromium (Total)	**9.62E-01**	1.30E-03
Chrysene	1.47E-03	
Copper	3.79E+00	9.30E+01
Cyclohexane	1.59E+02	
Ethylbenzene	1.45E+02	7.70E+04
Fluoranthene	2.75E-03	
Fluorene	9.71E-03	
Formaldehyde	**9.98E+01**	3.00E+01
n-Hexane	1.74E+03	2.70E+05
1,2,3,4,7,8 -HxCDD	1.11E-06	
1,2,3,6,7,8- HxCDD	2.72E-06	
1,2,3,7,8,9- HxCDD	1.79E-06	
1,2,3,4,7,8 -HxCDF	1.52E-05	
1,2,3,6,7,8- HxCDF	1.15E-05	

Substance	Emissions, lb/yr	BAAQMD Trigger Level, lb/yr
2,3,4,6,7,8- HxCDF	1.00E-05	
1,2,3,7,8,9- HxCDF	1.40E-06	
1,2,3,4,6,7,8- HpCDD	9.73E-06	
1,2,3,4,6,7,8- HpCDF	5.14E-05	
1,2,3,4,7,8,9- HpCDF	4.66E-06	
Hydrogen sulfide	2.06+03	3.9E+02
Indeno(1,2,3-cd)pyrene	9.26E-02	0.011*
Lead	4.40E+00	5.40E+00
Manganese	6.12E+00	7.70E+00
Mercury	1.62E-01	5.60E-01
Naphthalene	**1.18E+01**	5.30E+00
Nickel	**8.47E+00**	7.30E-01
OCDD	4.90E-06	
OCDF	1.21E-05	
PCBs (Total)	4.44E-03	
1,2,3,7,8 -PeCDD	9.19E-07	
1,2,3,7,8 -PeCDF	5.51E-06	
2,3,4,7,8 -PeCDF	7.51E-06	
Phenanthrene	1.31E-02	
Phenol	5.08E+00	7.70E+03
Propylene	1.95E+00	1.20E+05
Pyrene	2.23E-03	
Selenium	1.76E-02	7.70E+02
Silver	1.45E+00	
Sulfuric Acid Mist	1.13+04	3.9E+01
2,3,7,8-TCDD	5.12E-08	
2,3,7,8-TCDF	1.95E-06	
Toluene	8.98E+02	1.20E+04
1,2,4-Trimethylbenzene	1.82E+02	
Xylene (Total)	6.20E+02	2.70E+04
Zinc	1.87E+01	1.40E+03

Following is a summary of the increases in toxic air contaminants at the hydrogen plant:

Substance	Emissions, lb/yr	BAAQMD Trigger Level, lb/yr
Acenaphthene	2.27E-02	
Acenaphthylene	1.49E-02	

Substance	Emissions, lb/yr	BAAQMD Trigger Level, lb/yr
Acetaldehyde	1.48E+02	6.40E+01
Acrolein	4.69E-02	2.30E+00
Ammonia	5.38E+04	7.70E+03
Antimony	4.98E+00	7.70E+00
Arsenic	8.19E+00	1.20E-02
Benzene	6.24E+02	6.40E+00
Benzo(a)anthracene	3.09E-01	0.011b
Benzo(a)pyrene	8.63E-01	0.011b
Benzo(b)fluoranthene	3.89E-01	0.011b
Benzo(k)fluoranthene	2.32E-01	0.011b
1,3-Butadiene	4.84E+00	1.10E+00
Cadmium	9.52E+00	4.50E-02
Chlorine	3.95E-02	7.70E+00
Chloroform	9.94E+00	3.40E+01
Chromium (Total)	1.03E+01	1.30E-03
Chrysene	1.57E-02	
Copper	4.06E+01	9.30E+01
Ethylbenzene	2.98E+02	7.70E+04
Fluoranthene	2.95E-02	
Fluorene	1.04E-01	
Formaldehyde	1.08E+03	3.00E+01
n-Hexane	7.63E+00	2.70E+05
Indeno(1,2,3-cd)pyrene	9.93E-01	0.011*
Lead	4.71E+01	5.40E+00
Manganese	6.56E+01	7.70E+00
Mercury	1.73E+00	5.60E-01
Methanol	1.75E+04	1.50E+05
Naphthalene	3.08E+00	5.30E+00
Nickel	9.08E+01	7.30E-01
Phenanthrene	1.41E-01	
Phenol	5.43E+01	7.70E+03
Propylene	3.24E+01	1.20E+05
Pyrene	2.39E-02	
Selenium	1.89E-01	7.70E+02
Silver	1.55E+01	
Sulfuric Acid Mist	8.60+2	3.9E+01

Substance	Emissions, lb/yr	BAAQMD Trigger Level, lb/yr
Toluene	1.03E+03	1.20E+04
1,2,4-Trimethylbenzene	4.98-01	
Xylene (Total)	3.60E+02	2.70E+04
Zinc	2.00E+02	1.40E+03

2.5 Mobile sources

Details of the emissions of mobile sources can be found in the Draft Environmental Impact Report that has been prepared by Contra Costa County. The District requires offsets only for emissions from cargo carriers that are not motor vehicles.

3. BACT and ract REVIEW AND DETERMINATION

In accordance with BAAQMD Regulation 2-2-301, the following sources will be subject to BACT because they are new sources that will emit more than 10 lb/highest day of POC, NOx, SO2, PM10, and/or CO.

S45, Heater (U246), 85 MMbtu/hr
S434, U246 High Pressure Reactor Train (Cracking) (23,000 bbl/day)
S1004, U235 Sulfur Recovery Unit (200 long tons/day)

In accordance with BAAQMD Regulation 2-2-301, the following sources will be subject to BACT because they are existing sources that emit more than 10 lb/highest day of POC, NOx, SO2, PM10, and/or CO, and the project will cause an emissions increase at the source.

S98, Tank 101, EFRT, 170k barrels
S122, Tank No. 167, EFRT, 3.1 MMgal
S123, Tank No. 168, EFRT, 75k barrels
S124, Tank No. 169, EFRT, 75k barrels
S128, Tank No. 174, EFRT, 76k barrels
S307, U240 Unicracking Unit
S308, U244 Reforming Unit
S309, U248 UNISAR Unit
S318, U76 Gasoline Blending
S339, U80 Gasoline/Mid Barrel Blending
S432, U215 Deisobutanizer

The following sources are not subject to BACT because the emissions from each of POC, NOx, SO2, PM10, and/or CO will be below 10 lb/highest day.

S118, Tank No. 163, fixed roof, 5.3k barrels
S465, Sulfur Pit U235 abated by S1003 or S1004, Sulfur Recovery Units
S503, Sulfur Storage Tank abated by S1003 or S1004, Sulfur Recovery Units

S504, Sulfur Degassing Unit abated by S1003 or S1004, Sulfur Recovery Units
S505, Sulfur Truck Loading Rack abated by S1004, U235 Sulfur Recovery Unit

The following sources are not subject to BACT because there will be no emissions increase at the sources.
S139, Tank No. 204, fixed roof, 81k barrels, abated by A7, Vapor Recovery System
S140, Tank No. 205, fixed roof, 54k barrels, abated by A7, Vapor Recovery System
S168, Tank No. 269, fixed roof, 39k barrels, abated by A7, Vapor Recovery System
S173, Tank No. 280 fixed roof, 134k barrels, abated by A7, Vapor Recovery System
S174, (Tank No. 281), fixed roof, 134k barrels, abated by A7, Vapor Recovery System
S182, Tank No. 294, fixed roof, 40k barrels, abated by A7, Vapor Recovery System
S464, Hydrogen Plant (not new source, was originally permitted as part of S307, U240 Unicracking Unit)

The following source will not be subject to BACT for POC because there will be a decrease in POC emissions increase at the source.
S1007, Dissolved Air Flotation Unit (DAF) abated by A49, DAF Thermal Oxidizer.
There will be an emissions increase of NOx, CO, PM, and SO2 at A49, DAF Thermal Oxidizer. However, A49 will not be subject to BACT for these pollutants because the emissions of each will be less than 10 lb/highest day.

Cargo carriers, and therefore locomotives, are not subject to BACT pursuant to BAAQMD Regulation 2-2-206.

Abatement devices
Secondary emissions from abatement devices are not subject to BACT, but are subject to RACT (reasonably available control technology) if the device complies with BACT for the primary pollutant, per the exemption in BAAQMD Regulation 2-2-112, which states:

> "The BACT requirements of Section 2-2-301 shall not apply to emissions of secondary pollutants which are the direct result of the use of an abatement device or emission reduction technique which complies with the BACT or BARCT requirements for control of another pollutant. However, the APCO shall require the use of Reasonably Available Control Technology (RACT) for control of these secondary pollutants. The Air Pollution Control Officer shall determine which pollutants are primary and which are secondary for the equipment being evaluated."

The following abatement devices are sources of secondary air pollutants:

A47, SCR abating S45, Heater

A49, DAF Thermal Oxidizer (440,000 btu/hr) abating S1007, Dissolved Air Flotation

A424, Tail Gas Incinerator abating A48, SRU Tail Gas Treatment Unit and S1004, Sulfur Recovery Unit

Following is the discussion of the BACT determinations for the sources that are subject to BACT in order of the magnitude of the emissions.

S1004, U235 Sulfur Recovery Unit (200 long tons/day)

S45, Heater (U246), 85 MMbtu/hr

Tanks: S98, S122, S123, S124, S128

Sources of fugitive emissions: S307, S308, S309, S318, S339, S432, S434

The abatement devices are discussed after the discussion of the BACT determinations.

3.1. S1004, U235 Sulfur Recovery Unit (200 long tons/day)

ConocoPhillips has proposed the following emission levels for the new Sulfur Recovery Unit:

Pollutant[1]	Emission Factor	`	Reference for BACT determination
NO_x	42.2 ppmv @ 7% O_2	0.0669	BACT Determination for ConocoPhillips Ferndale Refinery
SO_2	50 ppmv @ 0% O_2	NA	BACT Determination for Shell Martinez Refinery
PM10	7.6 lb/MMcf	0.0075	AP42 Section 1.4, Natural Gas Combustion
POC	5.5 lb/MMcf	0.0054	AP42 Section 1.4, Natural Gas Combustion
CO	75 ppmvd @ 7% O_2	0.0965	New BACT Determination

The proposed emissions are:

	Lb/hr	Lb/day	Ton/yr
NOx	2.56	61.3	11.2
SO_2	8.45	201	29.7
PM10	0.14	3.2	0.59
POC	0.1	2.3	0.43
CO	8.65	201	37.9

Based on this proposal, the sulfur recovery unit (SRU) is not subject to BACT for PM10 or POC. An initial source test will be required to confirm the low emissions of PM10 and POC.

SO2

The last BACT determination for an SRU made by the District was in Application 8407 for the Shell Refinery in 1993. At that time, BACT was only determined for SO2 and CO. The BACT determination for SO2 was:

- control by a SCOT unit and a tailgas incinerator
- 100 ppm total reduced sulfur @ 0% O2 on the feed to the tailgas incinerator
- 50 ppm SO2 @ 0% O2
- 2.5 ppm H2S @ 0% O2
- requirement to strip 95% by weight of the H2S and NH3 from the sour water stream

This unit will be controlled by an amine stripper and tailgas incinerator. The same concentration limit on SO2 will be imposed. The SO2 emissions compare favorably to the emissions from the Shell Refinery SRU, because the emissions will be similar—35 tons per year for Shell versus 36.7 tons per year for ConocoPhillips—but the capacity of the Shell SRU is 30% smaller—140 tons sulfur make per day for Shell versus 200 tons sulfur make per day for ConocoPhillips.

The BACT proposal also compares favorably to the BACT determination made for the proposed Arizona Clean Fuel Yuma facility. That SRU would have the following specifications:

- 33.6 lb SO2/hr or 806 lb SO2/day
- maximum capacity: 800 long tons/day
- nominal capacity: 608 long tons/day
- 99.97% recovery of sulfur

The ConocoPhillips SRU will have a capacity of 200 long tons per day and SO2 emissions of 201 lb/day. Therefore, about 1 lb SO2/long ton sulfur will be emitted. At maximum capacity, the proposed Arizona SRU will emit about 1 lb SO2/long ton sulfur. At nominal capacity, it will emit about 1.3 lb SO2/long ton sulfur.

After public comment, the refinery agreed to lower the annual SO2 emissions by an additional 7 tons per year at the SRU as an additional mitigation for CEQA. The final emission limit is 29.7 tons SO2 per year. At nominal capacity, this is equivalent to 0.8 lb SO2/long ton sulfur.

The facility has calculated emissions of H2S in the outlet and has accepted a limit of 2.5 ppmvd @ 0% O2. However, the facility has not provided an estimate for total reduced sulfur or reduced sulfur compounds at the outlet. The facility will be required to perform annual source tests for total reduced sulfur and reduced sulfur compounds to ensure that the trigger of 10 tons per year in BAAQMD Regulation 2-2-306 is not exceeded.

<u>CO</u>
The ConocoPhillips SRU is proposed to have CO emissions of 207 lb/day. Therefore, about 1.1 lb CO/long ton sulfur would be emitted.

Mass emissions of CO were not calculated for the SRU at the Shell refinery. The limit is 100 ppmv, dry, @ 0% O2. ConocoPhillips is proposing 75 ppmv, dry, @ 7% O2, which is equivalent to 8.65 lb/hr. The facility’s original proposal was 57.1 ppmv, dry, @ 7% O2, which is equivalent to 6.58 lb/hr, but was found by the designers not to be feasible.

The Arizona SRU is permitted to emit 36.8 tons CO/yr or 0.25 lb CO/long ton S at maximum capacity and 0.33 lb CO/long ton at nominal capacity. However, this is not achieved in practice, since the unit has not been built. The CO emissions are based purely on the thermal oxidizer heat input, using AP42 factors and may be overly optimistic. There are no emission limits for CO in the permit, according to the Statement of Basis.

The CO limits at the ConocoPhillips refinery in Ferndale, Washington, are 8.3 tons CO/yr and 42.2 ppmv, dry. Its capacity is 65 tons/day. Therefore, the rate of CO emissions is 0.7 lb CO/long ton sulfur.

<u>NOx</u>

The ConocoPhillips SRU is proposed to have NOx emissions of 61 lb/day. Therefore, about 0.3 lb NOx/long ton sulfur would be emitted.

Mass emissions of NOx were not calculated for the SRU at the Shell refinery.

The Arizona SRU is permitted to emit 26.3 tons NOx/yr or 0.18 lb NOx/long ton S at maximum capacity and 0.23 lb NOx/long ton at nominal capacity. The emissions are based solely on NOx formation in the thermal oxidizer. The BACT determination is 0.06 lb NOx/MMbtu. The capacity of the thermal oxidizer is 100 MMbtu/hr. Again, this is not achieved in practice, since the unit has not been built.

The NOx limits at the ConocoPhillips refinery in Ferndale, Washington, are 9.88 tons NOx/yr and 42.2 ppmv, dry. Its capacity is 65 tons/day. Therefore, the rate of NOx emissions is 0.7 lb NOx/long ton sulfur.

Conclusion: The SRU meets BACT for SO2, NOx, and CO. The proposed NOx emissions are lower, and the proposed CO emissions are higher, than those for the Ferndale refinery. This tradeoff is appropriate because the Bay Area is in attainment with all ambient air quality standards for CO.

ConocoPhillips has asked for a short-term limit of 8.0 lb NOx/hr, the effects of which will be included in the annual limit. As of March 9, 2007, this short term limit has not been included in the PSD modeling, but it is not expected to have an important impact. (This modeling is not required, as explained in Section 2.3.)

3.2. S45, Heater (U246), 85 MMbtu/hr

ConocoPhillips has proposed the following BACT levels for the new heater:

Pollutant	BACT	Technology	Reference
NOx	7 ppmvd @ 3% O2	Low-NOx burner and SCR	BAAQMD BACT Determination for U-110 (Application 11293)
CO	28 ppmvd @ 3% O2	Good combustion practice	BAAQMD BACT Determination for ULSD (Application 5814)
SO2	Use of natural gas and/or RFG; 100 ppmv total sulfur in RFG	Fuel selection	BAAQMD BACT Determination for ULSD Project and Guideline 94.3.1
POC	Use of natural gas and/or RFG 5.5 lb/MMcf	Fuel selection and good combustion practice	BAAQMD BACT Guideline 94.3.1
PM10	Use of natural gas and/or RFG 7.6 lb/MMcf	Fuel selection	BAAQMD BACT Guideline 94.3.1

Based on the proposed emissions below, the heater is subject to BACT for NOx, CO, SO2, and PM10.

	lb/hr	lb/day	ton/yr
NOx	0.73	18	3.2
SO_2	1.07	26	4.7
PM10	0.48	12	2.1
POC	0.35	8.4	1.5
CO	1.79	43	7.8

The NOx, CO, and SO2 levels that ConocoPhillips has proposed are lower than the District's current BACT handbook.

The 100 ppmv total sulfur limit is lower than the 100 ppmv TRS limit in the BACT handbook, which only includes hydrogen sulfide, methyl mercaptan, methyl sulfide, and dimethyl disulfide. Recent permits have had limits of 45 ppmv TRS as defined here. However, analyses of gas treated in the Merichem (type of caustic scrubber) unit show that H2S is generally below detectable levels and that the largest sulfur components are carbonyl sulfide (COS) and thiophenes. Placing a limit on total sulfur ensures that the SO2 emissions are not overstated. Moreover, ConocoPhillips is capable of testing for H2S and total sulfur. Analyzing for a myriad of sulfur compounds adds to the cost and difficulty of monitoring and is unnecessary.

ConocoPhillips has requested an annual average for flexibility with the total sulfur limit. The District agrees with the need for flexibility but considers that the period is too long to easily determine compliance and considers a rolling 365-day period too cumbersome. Instead, the limit will have a calendar month average.

BACT for particulate matter is not an emission level but rather use of natural gas or treated refinery fuel gas. The facility will comply with this requirement because the refinery fuel gas will be treated in a Merichem unit that will reduce the total sulfur to less than 100 ppmv on a monthly average.

ConocoPhillips has performed a top-down analysis of BACT for NOx and PM10 at S45, which is required as part of the PSD analysis. The analysis is attached in Appendix D.

After the permit was proposed, the District determined that the South Coast Air Quality Management District had made some BACT determinations that had not been published for heaters burning refinery fuel gas. The concentrations that have been achieved in practice are 5 ppmv NOx and 10 ppmv CO at 3% O2, dry, 3-hour average.

The facility will conform to this BACT determination except when operating at a third of its maximum capacity or less. The facility explained that the cracking process generates a great deal of heat, so full capacity is not required at all times. The NOx limit is achievable at lower capacity, but the CO limit is not. The CO limit will be 28 ppmv at 3% O2, dry, 3-hour average, when the heater is operating at 30 MMbtu/hr or less. The mass emission rate will be roughly equivalent to the mass emission rate at maximum capacity. The averaging time will be reduced to 3 hours.

Following are the amended emission factors:

Pollutant	BACT	Emission Factors (lb/MMbtu)
NOx	5 ppmvd @3% O2	0.0061
CO	10 ppmvd @3% O2	0.0075
SO2	Use of natural gas and/or RFG; 100 ppmv total sulfur in RFG	0.0126
POC	Use of natural gas and/or RFG 5.5 lb/MMcf	0.0041
PM10	Use of natural gas and/or RFG 7.6 lb/MMcf	0.0057

Following are the amended hourly, daily, and annual mass emission rates:

	lb/hr	lb/day	ton/yr
NOx	0.52	12.4	2.3
SO_2	1.07	26	4.7
PM10	0.48	12	2.1
POC	0.35	8.4	1.5
CO	0.64	15.3	2.8

3.3. S98, S122, S123, S124, S128, External Floating Roof Tanks

The following BACT condition will be imposed on S98, S122, and S128 in BAAQMD Condition 22963, part 4:

> The owner/operator shall equip S98, S122, S123, and S128 with a BAAQMD approved roof with mechanical shoe primary seal and zero gap secondary seal meeting the design criteria of BAAQMD Regulation 8, Rule 5. The owner/operator shall ensure that there are no ungasketed roof penetrations, no slotted pipe guide poles unless equipped with float and wiper seals, and no adjustable roof legs unless fitted with vapor seal boots or equivalent. [BACT, cumulative increase]

BAAQMD Condition 22478, part 7, already subjects S123 and S124 to BACT. The wording is identical to the condition for S98, S122, and S128.

3.4. S307, S308, S309, S318, S339, S432, S434

These process units will have some new components (valves, flanges, pumps, compressors, etc.). These new components will be subject to BACT for petroleum refinery fugitive emissions in accordance with the Section 3 of the District's BACT handbook, which is:

- Graphitic gaskets for flanges
- Live loaded packing systems and polished stems, or equivalent, for valves
- "Wet" dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas for hydrocarbon centrifugal compressors
- Seal-less design or dual mechanical seals with a heavy liquid barrier fluid, or equivalent, for pumps
- Fugitive equipment monitoring and repair program for all components

In the draft permit, the components were subject to Condition 21099 for fugitive components, which was written for the ULSD project in 2002. The components will now be subject to Condition 23725 because a new BACT determination has been made. The new condition contains explicit emission limits, a maximum annual emission rate for the new components as a group, and specifications for the types of components used. The leak rate for pumps and compressors has been lowered to 100 ppm. All pumps will be inspected, even those pumps that handle heavy liquids.

The new units, S434 and S1004, are subject to BAAQMD Regulation 8-28-302, which requires the installation of BACT on any pressure relief device. The BACT for new sources that is listed in the District's BACT Workbook is installation of a rupture disk and venting the pressure relief device to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. After discussions with the refinery, the District has determined that the rupture disks are unnecessary and may not be feasible where there are a high number of pressure cycles and high temperatures. The perceived advantage of the rupture disks is that they indicate whether there has been flow to the fuel gas recovery system. If this event is associated with flaring, knowing that the vessel was vented to the flare would aid in causal analysis. Refinery staff has stated that they will be able to determine whether venting of the vessel caused flaring by looking at the pressure data that they have for all vessels.

The modified units are also subject to this requirement. Therefore, a permit condition has been added for Sources S307, S308, S309, S318, S339, and S432, requiring the installation of BACT for the pressure relief devices. BACT for modified sources is venting the pressure relief device to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%.

S309 and S339 are not subject to the standard in BAAQMD Regulation 8-28-302 because they are not considered to be modified. Although the units will have a throughput increase and are no longer considered to be "grandfathered" units, no new components will be installed. Since the emissions from these sources are fugitive emissions, if there are no new components, there is no increase in emissions from these sources, the sources are not considered to be modified, and they are not subject to BACT.

Following is the discussion of the RACT or BACT determinations for the abatement devices that are subject to RACT or BACT in order of the magnitude of the emissions.

A47, SCR abating S45, Heater
A49, DAF Thermal Oxidizer abating S1007, Dissolved Air Flotation
A424, Tail Gas Incinerator abating A48, SRU Tail Gas Treatment Unit and S1004, Sulfur Recovery Unit

<u>3.5 A47, SCR abating S45, Heater</u>
The secondary pollutant that is emitted by the SCR is ammonia. Ammonia is not subject to BACT, because the only pollutants mentioned in BAAQMD Regulation 2-2-301 are NOx, CO, POC, PM10, SO2, and NPOC. However, the facility has agreed to a 15-ppm ammonia slip. The ammonia slip was 10 ppm before a new BACT determination was made lowering the NOx concentration at the heater to 5 ppm. A higher ammonia slip is required to meet this lower limit.

<u>3.6 A49, DAF Thermal Oxidizer (440,000 btu/hr) abating S1007, Dissolved Air Flotation (DAF) Unit</u>
This abatement device is a thermal oxidizer that will burn vapors containing POC and H2S that are emitted by the atmospheric vents at the DAF. As stated in BAAQMD Regulation 2-2-112, shown above, emissions of secondary pollutants are subject to RACT if the required level of control for the primary pollutant complies with BACT. In this case, POC is the primary pollutant. NOx, CO, SO2, and PM10 are the secondary pollutants. Since POC levels from the DAF will be reduced, BACT is not triggered for POC and RACT is not triggered for the secondary pollutants.

Following are the emissions of secondary pollutants:

	Lb/day			
Source	**NOx**	**SO2**	**PM10**	**CO**
S1007, Dissolved Air Flotation (DAF) Unit	1.2	6.6	0.01	0.87

<u>3.7 A424, Tail Gas Incinerator abating A48, SRU Tail Gas Treatment Unit and S1004, Sulfur Recovery Unit</u>

RACT for this abatement device has not been considered. Instead, the entire sulfur recovery system including the Claus unit, the tail gas treatment unit, and the tail gas incinerator has been reviewed as a unit for BACT. This approach makes it possible to compare this sulfur recovery unit with others that have been built in the United States.

ConocoPhillips has performed a top-down analysis of BACT for NOx and PM10 at the hydrogen plant furnace, which is required as part of the PSD analysis. The analysis is attached in Appendix D.

4. CUMULATIVE INCREASE AND OFFSETS

The cumulative increase for the project is shown below.

	Tons per Year				
	NOx	**SO2**	**PM10**	**POC**	**CO**
ConocoPhillips Refinery	-22.9	35.8	0.8	-25.1	-2.2
Hydrogen Plant	30.9	5.0	13.8*	13.9*	46.2
ConocoPhillips Carbon Plant		-42.0			
Total	8.0	-1.2	14.6	-11.2	44

*The emissions from the exempt cooling tower at the hydrogen plant and the exempt butane loading rack at the refinery are not considered to be part of the cumulative increase and are not subject to offsets.

Offsets are required by BAAQMD Regulation 2-2-302 for NOx and POC because the emissions of the facility, which includes the ConocoPhillips refinery (BAAQMD Facility A0016), the ConocoPhillips carbon plant (BAAQMD Facility A0022), and the hydrogen plant (BAAQMD Facility B7419), are greater than 35 tons per year. In 2005, the refinery emitted approximately 335 tons NOx and 283 tons POC and the carbon plant emitted approximately 532 tons NOx in 2005 according to District estimates.

Offsets are required by BAAQMD Regulation 2-2-303 for SO2 and PM10 at major facilities. Major facilities, for the purpose of this requirement, are those that emit more than 100 tons per year of NOx, CO, SO2, PM10, or POC.

ConocoPhillips is a major facility for PM10 because in 2005 the refinery emitted approximately 126 tons PM10 and the carbon plant emitted approximately 63 tons PM10 in 2005 according to District estimates. It is a major facility for SO2 because in 2005 the refinery emitted approximately 424 tons SO2 and the carbon plant emitted approximately 1212 tons SO2 in 2005, according to District estimates.

Offsets are not required for CO, but 43.4 tons/yr are being provided through the shutdown of S8, Heater. The reduction is included in the emission totals for the refinery.

Contemporaneous offsets and banked offsets of SO2 and PM10 can be used at a 1.0:1.0 ratio. Banked offsets of NOx or POC must be used at a 1.15:1.0 ratio. ConocoPhillips will provide contemporaneous offsets from the following sources:

- S8, Heater: shutdown
- S352-S357, Steam turbine plant: voluntary overcontrolling of NOx emissions
- S1007, Dissolved Air Flotation Unit: voluntary overcontrolling of POC emissions
- BAAQMD Plant A0022, S2, Kiln: voluntary SO2 reductions (Application 15328)

In accordance with BAAQMD Regulation 2-2-302.2, POC credits shall be used to offset part of the NOx increases.

In previous applications, the District had not considered the carbon plant when processing permits for the refinery. Therefore, offsets were not required for PM10. In this application, all increases in PM10 at Facility A0016 since April 5, 1991, will require offsets. Following is a list of relevant applications and PM10 increases:

Application 5814	4.670 tons
Application 11293	0.300 tons
Application 12412	7.670 tons
Total	12.640 tons

Also, 0.120 tons of SO2 associated with Application 11293 will be offset at the refinery. These offsets had previously not been provided.

Following are details of the contemporaneous offsets:

S8, Heater: Shutdown of S8 will provide 16.7 tons NOx/yr, 2.9 tons PM10/yr, 2.1 tons POC/yr, and 43.4 tons CO/yr.

S352-S354, Turbines, and S355-S357, Duct Burners (Steam Power Plant): Permit condition 12122, part 9, currently allows annual NOx emissions from the Steam Power Plant of 167 tons/year. The actual emissions, as shown by CEM data, averaged 101.9 tons per year. The facility has proposed a new annual limit of 79.8 tons per year to provide 22.1 tons/yr of NOx offsets.

S1007, Dissolved Air Flotation Unit: The facility has proposed to control 44.1 tons per year of POC emissions at the DAF unit for the purpose of generating contemporaneous offsets. These emissions do not require a RACT adjustment because they were considered for control during the 2004 revisions of the BAAQMD Regulation 8, Rule 8, Wastewater Collection and Separation Systems, and were not regulated at that time. The facility has concluded that control of 44.1 tons per year is feasible, based on their measurements of flow at the atmospheric vents, the District's analysis of grab samples, and modeling of the wastewater system. Permit conditions will require the facility to demonstrate that they are collecting and oxidizing or abating the entire amount of POC. Otherwise, the facility will have to provide offsets from another source.

Facility A0022, S2, Kiln: This source is at the ConocoPhillips Carbon Plant, which is part of this facility. The kiln is used to drive sulfur from coke that is produced at the refinery. The purified coke is a saleable product. The kiln has an SO2 CEM that measures compliance with the 400 ppm or 250 lb/hr standard in BAAQMD Regulation 9-1-310.2, therefore the facility has good records of the SO2 emissions.

The facility submitted Application 15328 with a proposal for generating contemporaneous SO2 emission reduction credits (ERCs) from the kiln. The 3-year baseline annual average SO2 emissions were determined to be 791.32 tons/yr. The new SO2 limit will be 749.32 tons per year as verified by the SO2 CEM. This will provide 42 tons per year of SO2 ERCs.

In determining creditable ERCs under Section 2-2-605, the proposed additional SO2 reductions from the kiln were not reduced by a RACT-adjustment due to considerations of the cost-effectiveness of further controls required by Section 2-2-243.

A measure of cost effectiveness for new and modified sources is represented by EPA in their recent proposal for 40 CFR 60, Subpart J, Standards of Performance for Refineries. Following are the costs for control of SO2 emissions from various categories that were judged by EPA to be reasonable:

New Fluid Catalytic Crackers	Option 4	$1,000/ton
Modified Fluid Catalytic Crackers	Option 4	1,400/ton
Fluid Cokers	Option 2	210/ton
Sulfur Recovery Plants	Option 2	1,200/ton
Process Heaters/Other Combustion	Option 2	2,200/ton

The ConocoPhillips proposal would use the existing sodium bicarbonate system at the Carbon Plant to achieve the proposed SO2 emission reductions. Since the facility has already installed the system to ensure compliance with the limits in BAAQMD Regulation 9-1-310.2, the additional capital cost of increasing the level of control of SO2 as proposed would be minimal. The operating costs, including disposal of hazardous waste, have been determined to be $2700/ton SO2. This cost of control exceeds all of the cost-effectives figures judged by EPA to be reasonable in their recent proposed NSPS.

The District is also aware that the South Coast AQMD has a rule requiring 80% control of SO2 from coke calciners. This level of control has been achieved by the use of a wet scrubber. ConocoPhillips performed an analysis for a similar coke calciner at their Santa Maria refinery in San Luis Obispo County. The capital costs, operating costs, and $/ton removed are shown below:

Process	Capital Cost	Operating Cost	Removal Efficiency	$/ton removed
Wet Scrubber	$8.5 MM	$6.7 MM/yr	95%	$15,000
Dry Scrubber	$2.3 MM	$4.5 MM/yr	90%	$9,000

However, the South Coast is a non-attainment area for SO2. The South Coast rule represents a higher level of control that is well beyond RACT.

Based on the considerations of cost-effectiveness summarized above, no RACT adjustments were applied in determining creditable SO2 ERCs from the Carbon Plant kiln control proposal.
For the purposes of cumulative increase and offsets, any increase from cargo carriers that are not motor vehicles are included in the definition of facility in BAAQMD Regulation 2-2-215. In this case, cargo carriers would include marine vessels and locomotives.

It is expected that there will be a decrease in emissions from marine loading because the heavy gas oil that was formerly shipped out in ships and barges will be processed at the facility, but the decrease has not been quantified. The resulting gasoline and diesel may be shipped out via pipeline or ships. ConocoPhillips has no truck rack at the facility to distribute its products.

An increase in the emissions from locomotives due to this project has been included in the emission total.

Following is a summary of all emissions increases, decreases, and offsets required.

	NOx	**SO2**	**PM10**	**POC**	**CO**
Increases					
S45, New Unit 246 HGO Feed Heater	2.3	4.7	1.9	1.5	2.8
S434, New Unit 246 Startup/Shutdown	<0.01	<0.01	-	0.03	0.02

	NOx	SO2	PM10	POC	CO
S1004, New SRU (Unit 235)	11.2	29.7	0.59	0.4	37.9
Tanks 101, 168 & 169 Permit Cond. Change				8.1	
Existing Tanks				4.8	
Fugitives				6.1	
Paved Roads			1.1		
Locomotive Emissions	2.2	0.2	0.08	0.1	0.3
S1007, Dissolved Air Flotation (DAF) Unit	0.2	1.2	0.01		0.2
Hydrogen Plant	30.9	5	13.8	13.9	46.2
Decreases					
S8, Unit 240 Boiler B-1 Reductions	-16.7		-2.9	-2.1	-43.4
Refinery Steam Power Plant Reductions	-22.1				
S1007, Dissolved Air Flotation (DAF) Unit				-44.1	
A0022, S2, Kiln		-42			
Total decreases	-38.8	-42	-2.9	-46.2	-43.4
Total	**8.0**	**-1.2**	**14.6**	**-11.3**	**44.0**
Offset of NOx with POC	0	-1.2	14.6	3.3	44.02
Previous projects					
Application 5814			4.67		
Application 11293		0.12	0.3		
Application 12412			7.67		
Emissions requiring offsets			27.23		
Offsets required (1.0:1.0 ratio)			27.23		

The PM10 offsets will come from the following certificates:

Certificate Number	Owner of Record	Amount tpy
920	ConocoPhilips	6.650
979	Air Liquide	18.600
1032	Air Liquide	4.200
Total		29.45

5. STATEMENT OF COMPLIANCE

BAAQMD Regulation 1, General Provisions

S1004, Sulfur Recovery Unit, will be permitted to emit an average of 200 lb SO2/day, and therefore will be subject to the continuous emission monitoring requirements in Sections 1-520.4 and 1-522.

S1001-S1003 are smaller SRUs and are not subject to the requirement above because they do not emit more than 100 lb SO2/day. Compliance has been confirmed by source testing.

S45, Heater, and S1004, Sulfur Recovery Unit, will be subject to flow monitoring and therefore will be subject to the parametric monitoring requirements in Section 1-523.

A47, SCR, abating S45, Heater, will be subject to temperature monitoring and therefore will be subject to the parametric monitoring requirements in Section 1-523.

S49, DAF Thermal Oxidizer, will be subject to temperature monitoring and therefore will be subject to the parametric monitoring requirements in Section 1-523.

BAAQMD Regulation 2, Rule 5, New Source Review Of Toxic Air Contaminants

In accordance with BAAQMD Regulation 2, Rule 5, a health risk screening analysis was prepared by the facility and reviewed by District Staff. The project risk including Facility A0016, ConocoPhillips refinery, meets the requirements as follows:

- Project cancer risk is less than 10.0 in a million;

- Project chronic hazard index is less than 1.0; and
- Project acute hazard index is less than 1.0.

The cancer risk for S2, Heater, at Facility B7459, is greater than 1.0 in a million. Therefore, the source is subject to TBACT in accordance with Section 2-5-301 of the rule. TBACT is the use of extremely clean gaseous fuels. 85% of the fuel that will be burned in the Heater will be PSA gas, which is extremely clean and has very little sulfur.

Also, the risk assessment for S2 is conservative, because it was based on an average heat input rate of 1,100 MMbtu/hr, but the final average heat input rate will be 975 MMbtu/hr, which is 12.8% less.

The maximum chronic hazard index was less than 0.2 for the entire project.

BAAQMD Regulation 6, Particulate Matter and Visible Emissions

The following sources will not be sources of particulate matter because their emissions are routed back to the Claus unit at S1004, Sulfur Recovery Unit:

S465, Sulfur Pit
S503, Sulfur Storage Tank
S504, Sulfur Degassing Unit
S505, Sulfur Truck Loading Rack

The following sources are the new sources of particulate matter in this application:

S45, Heater
S1004, Sulfur Recovery Unit
A47, SCR abating S45, Heater
A49, DAF Thermal Oxidizer abating S1007, Dissolved Air Flotation Unit
A424, Tail Gas Incinerator, abating S1004, Sulfur Recovery Unit

S352-S354, Turbines, are existing sources of particulate matter that are expected to continue to comply with BAAQMD Regulation 6.

S45, Heater, and A47, SCR, are subject to Sections 6-301, 6-305, and 6-310.3. Section 6-301 is a requirement that visible emissions may not exceed 1.0 Ringelmann for more than 3 min/hr. Section 6-305 is a requirement that a unit may not emit visible particles that fall outside of the facility's property. Section 6-310.3 is the grain-loading limit for heat transfer operations of 0.15 gr filterable particulate/dscf @ 6% O2. (The "gr" used in this section means "grains," which are equal to 1/7000 of a pound.) S45 burns gaseous fuels and is expected to comply with these requirements.

Sources that burn refinery fuel gas and that use ammonia in SCR control systems have special source testing requirements because ammonium sulfate is produced as an artifact of the test in these circumstances. EPA has approved alternate test methods for this situation: Methods 201 and 202 with the back-half ammonium sulfate subtracted. The facility will use these methods to test this heater and SCR.

S1004, Sulfur Recovery Unit, and A424, Tail Gas Incinerator are subject to Sections 6-301, 6-305, 6-310, 6-311, 6-330, and 6-501 of the regulation. Sections 6-301 and 6-305 were described in the paragraph above. Section 6-310 is the general grain-loading limit of 0.15 gr filterable particulate/dscf. Section 6-311 is the process weight limit. Section 6-330 has a limit of 0.08 gr/dscf of SO3 or H2S04, or both, expressed as 100% H2S04, exceeding 0.08 gr/dscf of exhaust gas volume. "Filterable particulate" means particulate as measured by District Source Test Method ST-15, Particulate.

Based on experience with the 3 existing units, S1004 is expected to comply with Sections 6-301, 6-305, and 6-330. They are not generally sources of visible emissions and testing for the sulfuric acid mist standard in Section 6-330 is feasible and is being performed on an annual basis. It is not feasible to test the existing units for the filterable particulate standards in Sections 6-310 and 6-311 at this time because they do not have the required ports for source testing. The new unit will have the ports and will be tested on an annual basis.

The magnitude of the limit in Section 6-311 is determined by the process weight rate of the unit. Since the capacity of the unit is 200 long tons/day, the maximum process weight is 18,667 lb/hr, and the maximum limit is 18.3 lb filterable particulate/hr. If the process weight is less than 18,667 lb/hr, the limit is pro-rated using the equation in the section.

The facility has estimated that the S1004 will emit about 0.14 lb PM10/hr and about 1.29 lb sulfuric acid mist/hr. The facility has not estimated filterable particulate matter. The tests for sulfuric acid mist on the facility's 3 existing units have results of 0.015 gr/dscf or less. The facility estimates that the flowrate at the incinerator stack will be 2,623 lbmol/hr, excluding water and oxygen. This is equivalent to 996,000 dscf, using the ideal gas law. At this rate, the acid mist emission rate is expected to be approximately 0.009 gr/dscf.

The facility will be required to perform an initial and annual source test to assure compliance with Sections 6-310, 6-311, and 6-330. At this time, the filterable particulate concentration and mass emissions will be determined. They are expected to comply with Sections 6-310 and 6-311, especially because controlled sulfur recovery units generally do not have visible emissions, which are indicators of high particulate emissions.

As described above, S1004, Sulfur Recovery Unit, is expected to comply with all of the Regulation 6 standards.

A49, DAF Thermal Oxidizer, will be a small source of particulate. It is rated for 440,000 btu/hr, which includes approximately 10 lb/hr of organic vapors. The facility has estimated 0.0033 lb PM10/hr, using the factor for natural gas combustion in AP-42. Since this unit will burn natural gas and abate organic compound vapors, the source is expected to easily comply with the Regulation 6 standards, and a source test for particulate matter will not be required.

BAAQMD Regulation 7, Odorous Emissions

The purpose of Regulation 7 is the general control of odorous compounds. Most are discussed generally. A few are mentioned by name. One of these is ammonia.

S45, Heater, and S1004, Sulfur Recovery Unit, are sources of ammonia. Ammonia is used at S45 in the SCR for abatement of NOx. S1004 burns ammonia that is concentrated in the sour gas. Section 7-303 limits the concentration of ammonia from Type A emission points to 5000 ppm. A Type A emission point is defined in BAAQMD Regulation 1-230 as: " An emission point, having sufficiently regular geometry so that both flow volume and contaminant concentrations can be measured and where the nature and extent of air contaminants do not change substantially between a sampling point and the emission point." There is no correction for oxygen concentration. The heater will comply because it has a limit of 10 ppmv ammonia @ 3% oxygen. It is expected that the SRU will comply because tests for ammonia at the other SRUs have measured concentrations less than 10 ppm @ 15% O2 and the facility has proposed a limit at the SRU of 12.5 ppmdv @ 7% O2. The concentration of ammonia in the stacks of both sources will be measured by source test after construction.

Hydrogen sulfide is very odorous and is one of the compounds generated by various pieces of equipment in the refinery. Most of the H2S in the refinery is concentrated in sour gas streams that are sent to the sulfur recovery units, where H2S is converted to elemental sulfur. The SRU, S1004, is not expected to be a source of H2S because any residual H2S that exits the SRU and A48, SRU Tail Gas Treatment Unit, should be burned in A424, Tail Gas Incinerator. Nonetheless, the facility has requested a limit of 2.5 ppmdv H2S @ 0% O2, which is the same limit placed on S4180, Sulfur Recovery Unit, at the Shell Martinez refinery. Considering the 65-meter stack height of the SRU, H2S emissions at this concentration would not be expected to cause odor complaints. The source is expected to comply with BAAQMD Regulation 7. An initial source test will be required to confirm that the H2S concentration is below 2.5 ppmv @ 0% O2.

S465, Sulfur Pit, will not be a source of H2S because it will be abated by A1004, Sulfur Recovery Unit.

S504, Sulfur Degassing Unit, will remove H2S from molten sulfur. The facility estimates that the molten sulfur contains up to 800 ppmv H2S before degassing. After degassing, the sulfur will contain less than 10 ppmv H2S. The sulfur degassing unit will be abated by A1004, Sulfur Recovery Unit.

S503, Sulfur Storage Tank, and S505, Sulfur Truck Rack, will handle molten sulfur that contains less than 10 ppmw H2S. In addition, the tank and truck rack will also be controlled by A1004, Sulfur Recovery Unit.

S1007, DAF, will be less odorous after it is controlled pursuant to this application because it currently emits a small amount of H2S. It is currently in compliance with the odor regulation.

In addition to the requirements of this rule, BAAQMD Regulation 9, Rule 2; Hydrogen Sulfide, has limits on the ground level concentration for H2S and requires area monitoring for the refinery.

BAAQMD Regulation 8, Rule 5, Storage of Organic Liquids

The tanks affected by this project are:
S98, Tank 101, EFRT, 170k barrels
S118, Tank No. 163, fixed roof, 5.3k barrels
S122, Tank No. 167, EFRT, 3.1 MMgals
S123, Tank No. 168, EFRT, 75k barrels
S124, Tank No. 169, EFRT, 75k barrels
S128, Tank No. 174, EFRT, 76k barrels
S139, Tank No. 204, fixed roof, 81k barrels, abated by A7, Vapor Recovery System
S140, Tank No. 205, fixed roof, 54k barrels, abated by A7, Vapor Recovery System
S182, Tank No. 294, fixed roof, 40k barrels, abated by A7, Vapor Recovery System

The service for S98, Tank 101, EFRT, 170k barrels, will change from exempt diesel service to petroleum fluids with a vapor pressure up to 10 psia. Section 8-5-301 requires control by an internal floating roof, an external floating roof, or an approved emission control system. The tank has an external floating roof. The tank will be subject to Sections 8-5-111, 8-5-112, 8-5-301, 8-5-304, 8-5-320, 8-5-321, 8-5-322, 8-5-328, 8-5-331, 8-5-332, 8-5-401, and 8-5-501. The tank is expected to comply after retrofits.

S118 will continue to be exempt from Regulation 8, Rule 5 due to low vapor pressure.

S122, S123, S124, and S128 are already subject to the requirements for external floating roof tanks in Regulation 8, Rule 5.

S139, S140, and S182 are already subject to the requirements for pressure vacuum valves and approved emission control systems in Regulation 8, Rule 5.

None of the tanks except S98 are changing service, although the throughput will change. The tanks are in compliance with the relevant standards and are expected to continue to comply.

BAAQMD Regulation 8, Rule 10, Process Vessel Depressurization

The new Unicracker vessel, S434, and the new SRU, S1004, will be subject to this rule. All of the other process vessels mentioned are already subject. Section 301 of the rule requires that the emissions during depressurizing be controlled by an abatement device or the fuel gas system until the vessel is as close to atmospheric pressure as possible, but at least until the partial pressure of organic compounds in that vessel is less than 4.6 psig.

Section 302 requires that no process vessel may be opened to the atmosphere unless the internal concentration of total organic compounds has been reduced prior to release to atmosphere to less than 10,000 parts per million (ppm), with the following exception: vessels may be opened when the concentration of total organic compounds is 10,000 ppm or greater provided that the total number of such vessels opened with such concentration during any consecutive five year period does not exceed 10% of the total process vessel population, the organic compound emissions from the opening of these vessels does not exceed 15 pounds per day and the vessels are not opened on any day on which the APCO predicts an exceedance of a National Ambient Air Quality Standard for ozone or declares a Spare the Air Day.

The facility is expected to comply with these standards.

BAAQMD Regulation 8, Rule 18, Equipment Leaks

Components such as valves, flanges, pumps, compressors, pressure relief devices, are subject to BAAQMD Regulation 8, Rule 18. The rule has total organic leak limits of 100 ppm for valves and flanges and 500 ppm for pumps, compressors, and pressure relief devices. This is a "work-practice" standard. The facility is obligated to test the components for leaks on a periodic basis and repair the leaks. A small percentage of non-repairable leaks are allowed until the next turnaround or five years, whichever is sooner.

The facility has an inspection program for this regulation and is expected to comply with these standards for the new sources because the components will meet BACT, which was defined in Section 3.4 of this evaluation.

BAAQMD Regulation 8, Rule 28, Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants

BAAQMD Regulation 8, Rule 28 applies to pressure relief devices (PRD) installed on refinery equipment. Section 8-28-302 applies to PRDs on new or modified equipment. It requires that these PRDs comply with all requirements of BAAQMD Regulation 2, Rule 2, including BACT. BACT1 at this time is a rupture disk with a vent to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. All new PRDs installed pursuant to this project are subject to this standard.

Existing PRDs associated with the following units are also subject to the standard: S307, S308, S318, S432, S434, S1004. These PRDs will be subject to BACT2, which is a vent to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%.

S309 and S339 are not subject to the standard in BAAQMD Regulation 8-28-302 because they are not considered to be modified. Although the units will have a throughput increase and are no longer considered to be "grandfathered" units, no new components will be installed. Since the emissions from these sources are fugitive emissions, if there are no new components, there is no increase in emissions from these sources, the sources are not considered to be modified, and they are not subject to Section 8-28-302. S309 and S339 will continue to comply with Section 8-28-303, Existing Pressure Relief Devices at Petroleum Refineries.

The sulfur pits, S301-S303 and S465 are not subject to Regulation 8, Rule 28, because Section 8-28-101 states that the rule applies to equipment handling gaseous organic compounds at petroleum refineries. The sulfur pits do not handle gaseous organic compounds. However, the SRUs at ConocoPhillips do handle gaseous organic compounds and are subject to the standard.

Permit conditions with the BACT requirement will be added to these units. The facility is expected to comply with this requirement.

BAAQMD Regulation 9, Rule 1, Sulfur Dioxide
S45, Heater, and S1004, SRU, are sources of SO2. The heater is not subject to the 300-ppm limit in Section 9-1-301 of the rule because the refinery complies with the exemption in Section 9-1-110. The exemption requires ground level monitoring and compliance with the ground level concentration limit.

S1004 is subject to the limit of 250 ppmv SO2, dry, at zero percent O2, in Section 9-1-307. The source will be subject to continuous monitoring by BAAQMD Regulations 1-520, 1-522, and 9-1-502, which will ensure compliance.

BAAQMD Regulation 9, Rule 2, Hydrogen Sulfide
The facility is subject to the requirements of this rule. Many pieces of equipment that are being considered in this application can be sources of fugitive hydrogen sulfide: The facility has ground level monitoring of H2S to ensure compliance with the ground level concentration limits of 0.06 ppm averaged over three consecutive minutes or 0.03 ppm averaged over any 60 consecutive minutes. These requirements have been incorporated into the Title V permit and apply to the facility as a whole. Therefore, the facility complies with the requirement.

Also, see the discussion of H2S containing sources in the discussion for BAAQMD Regulation 7, Odorous Emissions.

BAAQMD Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations
S45, Heater, is not subject to the rule because it applies to new heat transfer operations with a maximum heat input greater than 250 MMbtu/hr, per Section 9-3-303.

BAAQMD Regulation 9, Rule 10, Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries
S45, Heater, is not subject to BAAQMD Regulation 9, Rule 10, because it applies to affected units. Units are defined by Section 9-10-220 as "any petroleum refinery boiler, steam generator, or process heater… having an Authority to Construct or a Permit to Operate prior to January 5, 1994." This heater will be subject to current BACT limits for NOx and CO, which are more stringent, instead of the Regulation 9, Rule 10, limits.

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 (CDD). The CDD 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 CDD in November 2006. 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 CDD on the draft EIR. These comments, as well as others received by CDD have been addressed in a revised EIR.

On September 25, 2007, the final EIR was certified by the Contra Costa County Board of Supervisors*.* The District must act on the application within 30 days of the certification.

As a responsible agency, the District has prepared findings for the purposes of CEQA. They are attached in Appendix G.

Prevention of Significant Deterioration

Emissions increases over 40 tpy NOx, POC, or SO2, over 100 tpy CO, and over 15 tpy PM10 are defined as major modifications by BAAQMD Regulation 2-2-221 if they occur at a major facility. BAAQMD Regulation 2-1-204 defines ConocoPhillips as a major facility. Originally, ConocoPhillips estimated that the project would increase PM10 emissions by 16.5 tons per year, 1.5 tons per year over the PSD threshold of 15 tons per year. Therefore, the original project was subject to PSD for PM10 as required by BAAQMD Regulations 2-2-304.2 and 2-2-304.3.

A PSD analysis was submitted by the facility and reviewed by District staff. It was submitted for NOx as well as PM10. The NOx emissions are lower than were originally proposed. The results of the analysis indicate that the proposed Clean Fuels Expansion and Hydrogen Plant Project would not interfere with the attainment or maintenance of the applicable Ambient Air Quality Standards for NOx and PM10 and would not cause an exceedance of any applicable PSD increment. The analysis was based on EPA approved models and calculation procedures and was performed in accordance with BAAQMD Regulation 2-2-414. The report is attached in Appendix C.

The PSD analysis was based on a NOx emissions increase of 41.4 tons per year and a PM10 emissions increase of 23.8 tons per year.

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately demonstrates the air quality impacts of the CFEP project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the CFEP project, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for NO2 and PM10 or an exceedance of any applicable PSD increment.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation.

Please see Appendix C for further detail of the analysis.

The final proposed emissions of PM10 that is subject to PSD, including contemporaneous offsets, were dropped to 13.8 tons per year for Air Liquide and 0.7 for ConocoPhillips. Therefore, the project is no longer subject to PSD.

BAAQMD Regulation 2-2-306, Non-Criteria Pollutant Analysis, PSD, requires PSD air quality analysis if the daily or annual triggers are exceeded for lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and/or reduced sulfur compounds. Only the sulfur compounds are expected to be emitted at this project. Following is an accounting of the expected emissions and the triggers:

POLLUTANT	ANNUAL AVERAGE LIMIT (TON/YR)	EMISSION (TON/YR)	DAILY LIMIT (LB/DAY)	EMISSION (LB/DAY)
Sulfuric acid mist	7	6.64	38	36.4
Hydrogen sulfide	10	1.1	55	5.34
Total reduced sulfur including hydrogen sulfide	10	1.1	55	5.34
Reduced sulfur compounds including hydrogen sulfide	10	1.1	55	5.34

Air quality analysis has not been performed for these pollutants for this project. Limits have been placed on sulfuric acid mist and hydrogen sulfide emissions, which are calculated at 6.64 and 1.1 tons per year, respectively. A limit has not been place on total reduced sulfur or total reduced sulfur compounds. Instead, the facility will determine the rate of emissions of total reduced sulfur compounds at the SRU, the largest source of SO2, SO3, and sulfuric acid mist, on an annual basis. If the rate exceeds 2.2 lb/hr during the source test, the District will require PSD modeling or an increase in the SRU incinerator temperature to control total reduced sulfur compounds.

The District does not have general delegation for the PSD program. The delegation was withdrawn on March 3, 2003 because EPA had revised its program. However, EPA has granted PSD delegation for certain projects on a case-by-case basis, because the federal regulations for new sources were not significantly changed, according to EPA Region 9. On January 24, 2006, EPA did delegate this project to the District. A copy of the letter granting delegation is attached in Appendix F.

NSPS, EQUIPMENT LEAKS

The following sources will become subject to NSPS fugitive emission requirements due to this project: S307, S308, S309, S339, S432, S434, and S464. The new standards are 40 CFR 60, Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, and Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries.

NSPS, Subpart J

S45, Heater, S465, Sulfur Pit, and S1004, U235 Sulfur Recovery Unit, will be subject to 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries.

S45, Heater, is subject to the H2S limit for fuel in Section 60.104(a)(1) of 0.10 gr/dscf or approximately 160 ppm. S45 will comply because it will burn either refinery fuel gas that has been processed by the Merichem Unit or natural gas. The outlet of the Merichem Unit is tested for H2S three times per day by an H2S analyzer. The Merichem Unit is subject to an alternative monitoring plan in place of the continuous monitoring required by Section 60.105(a)(4).

S465, Sulfur Pit, and S1004, U235 Sulfur Recovery Unit, are subject to the SO2 limit in Section 60.104(a)(2)(i) of 250 ppm SO2 at zero percent excess air. Compliance will be assured by the continuous SO2 monitoring required by Section 60.105(a)(5).

A49, Thermal Oxidizer, is subject to the standard because it will burn fuel gas as defined by the NSPS: "any gas which is generated at a petroleum refinery and which is combusted." ConocoPhillips will be subject to the H2S standard in Section 60.104(a)(1) and to the continuous monitoring requirement in Section 60.105(a)(5).

EPA intends to propose changes to Subpart J in April 2007, and finalize changes by April 2008. If these changes allow refineries to use periodic monitoring for small sources instead of continuous monitoring, or exempts small sources from the standard or monitoring, the permit condition will allow ConocoPhillips to take advantage of changes in the standard when they are finalized.

NSPS, Subpart GG
S352-S354, Turbines, are subject to 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, because they were built after October 3, 1977. The limit in the standard for NOx is 110 ppmdv @ 15% O2, and the limit for SO2 is 0.8% S in fuel by weight. The sources are in compliance with both limits. The NOx CEM that is required by BAAQMD Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines, ensures compliance with the NOx limit, and the requirement to perform TRS analysis on the refinery fuel gas three times per day ensures compliance with the sulfur limit.

On July 8, 2004, EPA promulgated changes to the required monitoring for the NSPS. In Section 60.334(c), EPA allowed use of CEMs to determine compliance with the NOx limit.

NSPS, Subpart K
The current Title V permit states that S139 is exempt from 40 CFR 60, Subpart K, Standards of Performance for Storage Vessels for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, because it does not contain petroleum fluids. For the purposes of this NSPS, distillate oil, which it may contain, is not a petroleum fluid. The tank also handles sour water. An increase in sour water or distillate oil will not cause an increase in emissions and is not considered a modification for the purposes of the NSPS.

NSPS, Subpart Kb
The following tanks are not currently subject to Subpart Kb: S98, S118, S122, S123, S124, S128, S140, and S182.

Although the emissions will increase at S98, S123, and S124 due to changes in the petroleum fluids that they will hold, it is not considered an increase for the purposes of Subpart Kb because EPA has determined in the May 17, 1999 letter from Gerald Potamis of EPA Region 1 to Paul Flaherty of Arthur D. Little (attached in Appendix E) that switching from one petroleum fluid to another is not a modification pursuant to 40 CFR 60.14. Therefore, these tanks will not be subject to Subpart Kb.

Increases in throughput at S118, S122, S128, S140 and S182 are not considered modifications for the purposes of NSPS.

NSPS, Subpart GGG/VV, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

S433, U246 High Pressure Reactor Train, will be subject to Subpart GGG/VV. In addition, process streams containing >5% OHAP will be subject to 40 CFR 63 Subpart CC (MACT) requirements for equipment leaks. The components subject to these regulations will be required to be added to the refinery's current LDAR programs, and comply along with other process units at the facility that are already subject to these standards.

S1004, Sulfur Recovery Unit, is not subject to the standard because it is not a process unit as defined by Section 60.591, which states:

> "*Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

The sulfur recovery units are not assembled to produce intermediate or final products, and the feed to the sulfur recovery unit is not petroleum, unfinished petroleum derivatives, or an intermediate. It is true that sulfur is produced at the SRUs, but that is the unintended consequence of operating these control devices.

NESHAPS
Subpart CC
Tanks

Tanks S139, S140, and S182 are not subject to Subpart CC because they are routed to the fuel gas recovery system as allowed by Section 63.640(d)(5).

The requirements in Subpart CC for Tanks S118, S122, S123, S124, and S128 will not change.

Tank S98 will be subject to the requirements for Group 1 storage vessels because it is larger than 46,750 gallons (177 cubic meters), the vapor pressure will be greater than 1.5 psia (10.4 kilopascal), and it will be presumed to contain more than 4 percent by weight total organic HAP.

Miscellaneous process vents

The sulfur plant vents at S1004 are not subject to Subpart CC in accordance with Section 60.640(d)(4) and the vents are not considered miscellaneous process vents according to Section 60.641. This includes the vents for the sulfur pits, S301-S303, and S465. Also, vents from the control devices for the sulfur plant are not considered miscellaneous process vents.

The deaerator vents at the hydrogen plants are not considered miscellaneous process vents according to Section 60.641.

Relief valve discharges are not considered miscellaneous process vents.

Equipment Leaks
S434, U236 High Pressure Reactor Train, will be a new unit. Section 63.648 subjects new units to Subpart H.

The remaining units are considered existing and subject to 40 CFR 60, Subpart VV.

NESHAPS, Subpart UUU
S1004, U235 Sulfur Recovery Unit, is subject to 40 CFR 63, Subpart UUU. This standard is essentially equivalent to the SO2 standard in 40 CFR 60, Subpart J. The unit will comply with the SO2 standard and with the requirement for continuous SO2 monitoring.

NESHAPS, Subpart DDDDD
S45, Process Heater, is subject to 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. The DC Circuit Court vacated the standard on June 8, 2007. Where there is no MACT for a new source and the deadline for promulgation of a standard by EPA is past, local agencies must determine case-by-case MACT for the new source, in accordance with 40 CFR 63.52(a). The emission limit for S45 in the standard was 400 ppm CO. There were no other limits for gaseous-fueled boilers. A CO CEM was not required for units under 100 MMbtu/hr.

The reason that the court gave for vacating the MACT was that EPA had inappropriately classified solid waste incineration units that were subject to Section 129 of the Clean Air Act as solid fuel units that were subject to the MACT. This classification greatly increased the number of units subject to the MACT and therefore skewed the determination of the MACT floor. The court stated that the "universe of units … will be far smaller and more homogenous [sic]" after the solid waste units were taken out of the group of units affected. The court expects that the rule will change substantially when EPA considers the smaller pool of units.

One possible outcome is that the standards may become more stringent because the HAP emissions from the solid waste incineration units are expected to be higher. The MACT "floor" is based on the performance of the top 12 percent of the units in a category.

EPA had determined that CO was an appropriate surrogate for organic HAPs. The argument was that high CO was indicative of poor combustion and therefore, poor destruction of organic HAPs. This is a reasonable assumption.

Following are the CO limits proposed by EPA:

- New, large and limited use solid fuel units: 400 PPM @ 7% O2
- Small solid fuel units: None
- New, large and limited use liquid fuel units: 400 PPM @ 3% O2
- Small liquid fuel units: None
- New, large and limited use gaseous fuel units: 400 PPM @ 3% O2
- Small gaseous fuel units: None
- Existing units None

Small units are defined as units with a capacity less than 10 MMbtu/hr.

Gaseous-fueled units are not expected to be sources of metallic or inorganic HAP.

The MACT limit for S45, therefore, was 400 PPM @ 3% O2, which is equivalent to the BAAQMD Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, which was adopted in 1992.

The District does not have the resources to survey all industrial, commercial, and institutional boilers and process heaters in the United States and determine the MACT "floor." However, the District notes that the CO BACT limit in the District's BACT workbook for boilers over 50 MMbtu/hr has been 50 ppmv since 2005. For refinery process heaters over 50 MMbtu/hr, the BACT limit has been 50 ppmv since 1994. The South Coast AQMD has had BACT limits for CO of 50 ppm for boilers since 2000.

On page 1680, column 3, second paragraph, of the MACT proposal published on January 13, 2003, EPA states:

> "The approach that we use to calculate the MACT floors for new sources is somewhat different from the approach that we use to calculate the MACT floors for existing sources. While the MACT floors for existing units are intended to reflect the average performance achieved by a representative group of sources, the MACT floors for new units are meant to reflect the emission control that is achieved in practice by the best controlled source. Thus, for existing units, we are concerned about estimating the central tendency of a set of multiple units, while for new units, we are concerned about estimating the level of control that is representative of that achieved by a single best controlled source."

If we agree with EPA that low CO levels indicate low levels of organic HAPs, then lower CO levels are better than higher CO levels. Considering that the "best controlled sources" have CO levels that are 50 ppm or lower, 400 ppm cannot be considered to be the proper MACT limit for a new gaseous-fueled source. The source is subject to the following BACT CO limits: 10 ppm CO when operating above 30 MMbtu/hr and 28 ppm CO when operating below 30 MMbtu/hr. These levels will be considered to be presumptive MACT levels for this source until EPA re-proposes and re-promulgates MACT. Since it is not expected that EPA will propose limits that are lower than these limits, the source incurs no risk from this determination.

40 CFR 70, Title V

The facility is subject to the Title V program because it is a major facility as defined by BAAQMD Regulation 2-6-206. The date of Initial issuance of the Title V permit was December 1, 2003. The permit has been modified several times after initial issuance.

The changes proposed in this application require a significant revision of the Title V permit because the project contains:

- 2-6-226.2: The incorporation of a change considered a modification under 40 CFR Parts 60 (NSPS) and 63 (MACT)
- 2-6-226.4: The establishment of or change to a permit term or condition allowing a facility to avoid an applicable requirement
- 2-6-226.5: The establishment of or change to a case-by-case determination of any emission limit or other standard
- 2-6-226.6: The establishment of or change to a facility-specific determination for ambient impacts, visibility analysis, or increment analysis on portable sources

The revisions will be proposed in the Title V permit after the District has received public comment on and finalized the conditions.

40 CFR 72-78, ACID RAIN

Electricity will be generated using excess heat at the hydrogen plant. The hydrogen plant will not be subject to 40 CFR 72-78 because it will not sell electricity. The hydrogen plant or ConocoPhillips will consume all electricity that is produced. The standards apply only to "utilities," which are defined in 40 CFR 72.2 as "any person who sells electricity."

The Steam Power Plant at the refinery consists of three 16.6 MW turbines and 3 Heat Recovery Steam Generators with 3 duct burners. There are no steam turbines, so the power plant is a simple cycle power plant. The steam power plant is not subject to Acid Rain because Section 72.6(b)(2) exempts:

> "Any unit that commenced commercial operation before November 15, 1990 and that did not, as of November 15, 1990, and does not currently, serve a generator with a nameplate capacity of greater than 25 MWe."

MONITORING ANALYSIS

S45, Heater, 85 MMbtu/hr, has limits on hourly and annual heat input, concentration limits on NOx, CO, and NH3, lb/MMbtu limits on POC and PM10, annual mass emission limits on NOx, CO, POC, PM10, and SO2, and sulfur and H2S limits on the fuel. The heater will have a fuel meter to ensure compliance with the heat input limits. Since the heater is abated by an SCR, it will have a NOx CEM to ensure that the abatement device is in compliance. The refinery fuel gas is supplied from the Merichem unit and will be monitored for H2S with the alternative monitoring plan approved in Application 11626. In addition, total sulfur will be monitored 3 times/day. The owner/operator will perform a one-time test for compliance with the NOx, CO, POC, PM10, and ammonia limits. Non-compliance with the POC and PM10 are not expected at this source. The owner/operator will perform tests for CO twice per year. If the source is not in compliance with the CO limit more than once in every 3 year period, the owner/operator will have to install a CO CEM.

Tanks: BAAQMD Regulation 8, Rule 5, requires adequate monitoring. The seals and fittings on external floating roof tanks are now required to be inspected twice per year. Pressure relief devices on tanks must also be inspected twice per year.

S352-S357, Steam Power Plant: The NOx CEMs on the steam power plant will ensure compliance with the new annual limit.

S1004, U235 Sulfur Recovery Unit (SRU): The SRU will be equipped with SO2 and CO CEMs to ensure compliance with all SO2 and CO limits. Initial compliance with the SO2, NH3, CO, NOx, POC, filterable particulate, PM10, sulfuric acid mist, and H2S limits will be demonstrated by source test. The source test will be used to establish a temperature limit that will ensure that the H2S concentration after control is less than 2.5 ppmdv @ 0% O2. An annual source test will be performed to ensure compliance with the limits in BAAQMD Regulation 6, and the NOx, ammonia, H2S, and sulfuric acid mist limits.

S1007, Dissolved Air Flotation Unit (DAF): Compliance with the H2S limit in 40 CFR 60.104(a)(1) will be ensured by continuous monitoring of the H2S content of the vapors sent to the thermal oxidizer. Initial compliance with the POC collection and destruction limit will be demonstrated by source test or tests. The source test or tests will be used to establish a temperature limit that will ensure that the destruction efficiency will be maintained.

S465, Sulfur Pit, S503, Sulfur Storage Tank, S504, Sulfur Degassing Unit, and S505, Sulfur Truck Loading Rack will not be monitored because their vents are routed to the sulfur recovery units.

Fugitive emissions: S307, S308, S309, S318, S339, S432, S434: BAAQMD Regulation 8, Rule 18, requires adequate monitoring.

Facility A0022: Source 2, Kiln: The pre-existing SO2 CEM is adequate and appropriate monitoring for the new SO2 limit and the pre-existing annual source tests for particulate are adequate and appropriate monitoring for the new PM10 limit.

Overall annual emission limits have been imposed in Condition 22970, parts A.1-A.3, to ensure that the emissions of the project are less than the emissions proposed by the applicant. The reasons that this condition has been imposed is to allow the facility to exceed certain limits during startup and shutdown and still comply with the annual limits. Part A.4 contains the monitoring and reporting for these limits.

6. RECOMMENDATIONS

Issue an authority to construct for the following sources:

S45, Heater (U246), 85 MMbtu/hr abated by A47, SCR
S98, Tank 101, EFRT, 170k barrels
S118, Tank No. 163, fixed roof, 5.3k barrels
S122, Tank No. 167, EFRT, 3.1 MMgals
S123, Tank No. 168, EFRT, 75k barrels
S124, Tank No. 169, EFRT, 75k barrels
S128, Tank No. 174, EFRT, 76k barrels
S168, Tank No. 269, fixed roof, 39k barrels, abated by A7, Vapor Recovery System
S173, Tank No. 280 fixed roof, 134k barrels, abated by A7, Vapor Recovery System
S174, (Tank No. 281), fixed roof, 134k barrels, abated by A7, Vapor Recovery System
S465, Sulfur Pit U235 abated by S1004, Sulfur Recovery Unit
S307, U240 Unicracking Unit (increase of 23,000 bbl/day)
S308, U244 Reforming Unit (increase of 2,413 bbl/day)
S309, U248 UNISAR Unit (increase of 7,830 bbl/day)
S318, U76 Gasoline Blending (increase of 8,300,000 bbl/yr)
S339, U80 Gasoline/Mid Barrel Blending
S432, U215 Deisobutanizer (increase of 2,600 bbl/day)
S434, U246 High Pressure Reactor Train (Cracking) (23,000 bbl/day)
S503, Sulfur Storage Tank abated by S1004, Sulfur Recovery Unit
S504, Sulfur Degassing Unit abated by S1004, Sulfur Recovery Unit
S505, Sulfur Truck Loading Rack abated by S1004, Sulfur Recovery Unit
S1004, U235 Sulfur Recovery Unit (200 long tons/day)
S1007, Dissolved Air Flotation Unit (DAF) abated by A49, DAF Thermal Oxidizer
A7, Odor Abatement System
A47, SCR abating S45, Heater
A48, SRU Tail Gas Treatment Unit
A49, DAF Thermal Oxidizer abating S1007, Dissolved Air Flotation
A51, DAF Carbon Bed
A424, Tail Gas Incinerator abating S1004, Sulfur Recovery Unit

Modify BAAQMD conditions as shown below.

Issue a change of conditions for the following sources:S139, Tank No. 204, fixed roof, 81k barrels, abated by A7, Vapor Recovery System
S140, Tank No. 205, fixed roof, 54k barrels, abated by A7, Vapor Recovery System
S464, Hydrogen Plant
S352, Combustion Turbine
S353, Combustion Turbine
S354, Combustion Turbine
S355, Duct Burner
S356, Duct Burner
S357, Duct Burner

Issue a permit to operate for the following sources:
S139, Tank No. 204, fixed roof, 81k barrels, abated by A7, Vapor Recovery System
S140, Tank No. 205, fixed roof, 54k barrels, abated by A7, Vapor Recovery System
S182, Tank No. 294, fixed roof, 40k barrels, abated by A7, Vapor Recovery System
S464, Hydrogen Plant (not new source, was originally permitted as part of S307, U240 Unicracking Unit)

7. PERMIT CONDITIONS

ConocoPhillips will provide 44 tons per year of contemporaneous POC offsets by controlling emissions at S1007, Dissolved Air Flotation Unit (DAF). These emissions are surplus, because they are not otherwise controlled by District regulations or permit, or other federal, State or local requirements.

Part 7 of Condition 1440 was amended after public comment to make clear that control of emissions at S1007 are required when VOC emissions must be reduced to provide offsets for Application 13424.

Using a thermal oxidizer to control the DAF is also expected to reduce odors because the emissions of the DAF contain H2S. The conditions allow control with carbon when the thermal oxidizer is not working. Because carbon will not control H2S, a provision has been added requiring control with a thermal oxidizer or other equivalent control of H2S at least 90% of the time.

The conditions regarding the control of emissions have been reorganized and made clearer.

"BAAQMD Regulation 2, Rule 5" replaces the following basis for permit conditions: "Toxics Risk Management."

CONDITION 1440

CONDITIONS FOR S324, S381, S382, S383, S384, S385, S386, S387, S390, S392, S400, S401 S1007, S1008, S1009

1. S324 API Separator shall be operated such that the liquid in the main separator basin is in full contact with the fixed concrete roof. This condition shall not apply during separator shutdown for maintenance.
   [Cumulative Increase]

2. Diversions of refinery wastewater around the Water Effluent Treating Facility to the open Storm Water Basins (S1008, S1009) shall be minimized. These diversions shall not cause a nuisance as defined in District Regulation 7 or Regulation 1-301. [Cumulative Increase]

3. Records shall be maintained of each incident in which refinery wastewater is diverted to the open storm water basins. These records shall include the reason for the diversion, the total quantity of wastewater diverted to the basins, and the approximate hydrocarbon content of the water.
   [Cumulative Increase]

4. The following sources shall be vapor-tight as defined in Regulation 8, Rule 8:

a. Doors, hatches, covers, and other openings on the S324 API Separator, forebay, outlet basin, and channel to the S1007 DAF Unit.

~~b. Doors, hatches, covers, and other openings on the S1007 DAF Unit and the S400 Wet and S401 Dry Weather Sumps, except for the vent opening on these units.~~

c. Any open process vessel, distribution box, tank, or other equipment downstream of the S1007 DAF Unit (S381, S382, S383, S384, S385, S386, S387, S390, S392).

[Cumulative Increase]

5. Compliance with the VOC emission criteria of Part 4 shall be determined semi-annually and records kept of each inspection. These records shall be made available to District personnel upon request.
[Cumulative Increase]

6. The maximum wastewater throughput at the S324 API Separator and S1007 DAF Unit shall not exceed 7,500 gpm during media filter backwash and 7,000 gpm during all other times for each unit. Any modifications to equipment at this facility that increase the annual average waste water throughput at S324 and S1007 shall first be submitted to the BAAQMD in the form of a permit application.
[Cumulative Increase]

7. This part will apply after VOC emissions at S1007 must be reduced to provide offsets for Application 13424 per Condition 22970, Part B. The owner/operator shall ensure that S1007, DAF, is controlled by A49, DAF Thermal Oxidizer or A51, DAF Carbon Bed, at all times of operation of S1007, except for up to 175 hours per any consecutive 12-month period for startup, shutdown, or maintenance. The owner/operator must control with a thermal oxidizer at least 90% of the time on a consecutive 12-month basis, unless owner/operator controls H2S with an equivalent control device as determined by the APCO.
[Offsets, CEQA]

a. Through source testing as described in Part 7(b) and 7(c), the owner/operator must demonstrate that the total reduction of emissions through use of A49, DAF Thermal Oxidizer and/or A51, DAF Carbon Bed will result in a total reduction of 44 tons POC per year, considering that abatement will not occur with either abatement device up to 175 hours per year. If initial testing does not demonstrate total reduction of 44 tons POC per year, the owner/operator may choose to:

i. In the case of A49, DAF Thermal Oxidizer, perform 4 tests in one year and average the results. In this case, the tests will be performed no less than 2 months apart and no more than 4 months apart.

ii. In the case of A51, DAF Carbon Bed, average the results of one year’s worth of monitoring.

If, after further testing, a total of 44 tons worth of POC reduction is not demonstrated, the owner/operator will supply offsets necessary to ensure a total reduction of 44 tons per year POC pursuant to BAAQMD Regulation 2-2-302.

[Offsets, CEQA]

b. The following conditions apply to operation of A49, DAF Thermal Oxidizer:

  i. Within 90 days of the startup date of A49, DAF Thermal Oxidizer, the owner/operator shall perform a source test to determine the following:

    1. Mass emissions rate for POC that is collected and sent to A49.
    2. Mass emissions rate for POC after abatement by A49.
    3. Mass emissions rate for H2S that is collected and sent to A49.
    4. Mass emissions rate for H2S after abatement by A49.
    5. Mass emissions rate for SO2

  During the source test, the owner/operator shall determine the temperature required to achieve 98.0% destruction by weight of POC or a concentration of 10 ppmv POC at the outlet. The temperature shall become an enforceable limit.

  For the purposes of determining the amount of POC controlled, the owner/operator shall use District Method ST-7, Organic Compounds. The owner/operator shall submit the source test results to the District Source Test Manager, the District Permit Evaluation Manager, and the District Director of Compliance and Enforcement no later than 60 days after any source test.

  [Offsets, CEQA]

  ii. After the initial source test required in Part 8 of this condition, the minimum temperature determined shall become the minimum temperature limit for A49. A49 shall not be operated below the minimum temperature except during an “Allowable Temperature Excursion” as defined below:

    1. Operation of A49 within 20°F below the minimum temperature
    2. Operation of A49 more than 20°F below the minimum temperature for a period or periods which, when combined are less than or equal to 15 minutes in any hour; or
    3. Operation of A49 more than 20°F below the minimum temperature for a period or periods which when combined are more than 15 minutes in any hour, provided that all three of the following criteria are met:
      a. The excursion does not exceed 50°F below the minimum temperature;
      b. The duration of the excursion does not exceed 24 hours; and

c. The total number of such excursions does not exceed 12 per calendar year (or any consecutive 12 month period).

Two or more excursions greater than 15 minutes in duration occurring during the same 24-hour period shall be counted as one excursion toward the 12 excursion limit.

For each such excursion, sufficient records shall be kept to demonstrate that they meet the qualifying criteria described above. Records shall include at least the following information:

1. Temperature controller setpoint;
2. Starting date and time, and duration of each Allowable Temperature Excursion;
3. Measured temperature during each allowable Temperature Excursion;
4. Number of Allowable Temperature Excursions per month, and total number for the current calendar year; and
5. All strip charts or other temperature records.

[Offsets, CEQA]

iii. To determine compliance with the temperature limit in Part 9, A49, Thermal Oxidizer shall be equipped with a temperature measuring device capable of continuously measuring and recording the temperature in A49. The temperature device shall be installed and maintained in accordance with the manufacturer's recommendations, shall be ranged appropriately to measure the temperature limit determined, and shall have a minimum accuracy over the range of 1.0 percent of full-scale.

[Offsets, CEQA]

iv. Unless amendments to 40 CFR 60, Subpart J, remove applicability of the DAF vapors from that subpart, the owner or operator shall:

1. Ensure that the H2S content of the gas burned at A49 does not exceed 0.10 gr/dscf. (This condition will be deleted when the citation is added to the Title V Permit)
2. Install, calibrate, maintain, and operate a District-approved Continuous Emissions Monitoring System and recorder for H2S in the gas that is sent to A49. The owner/operator is not required to operate the CEMS when A49 is not being operated.

[40 CFR 60, Subpart J]

v. If 40 CFR 60, Subpart J is amended such that a continuous monitoring system is not required for A49, and the owner/operator does not install a Continuous Emissions Monitoring System, the owner/operator shall perform a source test to determine emissions

of SO_2 from A49, DAF Thermal Oxidizer using District Method ST-19A, Sulfur Dioxide, Continuous Sampling. The owner/operator shall submit the source test results to the District Source Test Manager, the District Permit Evaluation Manager and the District Director of Compliance and Enforcement no later than 60 days after any source test.
[Offsets, CEQA]

vi. If the continuous monitoring data per Part 7.b.iv or the Source Test Data per Part 7.b.v shows that the annual SO_2 emissions are greater than 1.2 tons per year, the owner/operator shall provide additional SO_2 offsets in accordance with BAAQMD Regulation 2-2-303.
[Offsets, CEQA]

c. The following conditions apply to A51, DAF Carbon Bed

i. A51 shall consist of two or more activated carbon vessels arranged in series, with at least one carbon vessel in service except for up to 175 hours per any consecutive 12-month period for startup, shutdown, or maintenance.
[Offsets, CEQA]

ii. Total emission reduction of A51 shall be demonstrated through use of an in-line flowmeter, and the results of monitoring per the conditions below.
[Offsets]

iii. The owner/operator of A51 shall monitor with a photo-ionization detector (PID), flame-ionization detector (FID), or other method approved in writing by the Air Pollution Control Officer at the following locations:
1. The stream prior to any carbon vessels
2. At the inlet to the last carbon vessel in series
3. At the outlet of the carbon vessel that is last in series prior to venting to atmosphere
[Offsets]

iv. When using an FID to monitor breakthrough, readings may be taken with or without a carbon filter tip fitted on the FID probe. Concentrations measured with the carbon filter tip in place shall be considered methane for the purpose of these permit conditions.
[Offsets]

v. All breakthrough monitoring readings shall be recorded in a monitoring log each time they are taken. Readings shall be conducted on a daily basis initially, but after two months of daily collection, the owner/operator may propose for District review, based on actual measurements taken at the site during operation of the source, that the monitoring schedule be changed to weekly based on the demonstrated breakthrough rates of the carbon vessels. If the District Engineering Division does not disapprove of the proposed monitoring changes within 30 days, the owner/operator shall commence weekly monitoring.

[Offsets]

vi. The owner/operator shall utilize the activated carbon vessels in such a manner to ensure that the outlet stream to atmosphere contains below 10 ppm VOC or 98% reduction of VOC, whichever is greater.

[Offsets]

vii. The owner/operator of this source shall maintain the following records for each month of operation of A51:

1. The hours and times of operation
2. Each monitor reading or analysis result for the day of operation they are taken.
3. The number of spent carbon beds removed from service.

[Offsets]

8. This part will apply after VOC emissions at S1007 must be reduced to provide offsets for Application 13424 per Condition 22970, Part B. Any exceedance of any limit in part 7 shall be reported to the Compliance and Enforcement Division within 10 days of discovery of the occurrence. (This condition will be deleted when the condition is added to the Title V Permit.) [basis: Offsets; CEQA; 40 CFR 60, Subpart J]

9. This part will apply after VOC emissions at S1007 must be reduced to provide offsets for Application 13424 per Condition 22970, Part B. The owner/operator shall seal the DAF outlet channel and downstream sumps by a solid cover with gaskets. Any vents installed on the covered channel shall be routed to the thermal oxidizer or an equivalent control as determined by the APCO. [Offsets, CEQA]

The title of Condition 1694 has been changed to show that the emissions from engines are not included in the SO2 cap. When this condition was written, the engines were exempt and the emissions from engines were not considered. Also, the new heater, S45, will not be included in the SO2 cap.

S336 and S337 have been moved from part A.1a to A.1b because they are not grandfathered sources. They were modified in 1999 pursuant to Application 18696 to retrofit the burners for compliance with BAAQMD Regulation 9, Rule 10.

S8 will be removed from part A.1b because it will be removed from service. The SO2 cap in part A.4 will not change because the refinery fuel gas will be burned in other sources.

The overall fuel firing for Sources S2, S3, S4, S5, S7, S9, S10, S11, S12, S13, and S14, Heaters, in part F.1b will be reduced by 115.7 MMbtu/hr when S8 is removed from service, based on the baseline for S8.

CONDITION 1694

CONDITIONS FOR COMBUSTION SOURCES AND SO2 CAP, EXCEPT FOR GAS TURBINES, DUCT BURNERS, ENGINES, AND S45, HEATER (U246 B801/B802)
-
A. Heater Firing Rate Limits and General Requirements

1a. Each heater listed below shall not exceed the indicated daily firing rate limit (based on higher heating value of fuel), which are considered maximum sustainable firing rates. The indicated hourly firing rate is the daily limit divided by 24 hours and is the basis for permit fees and is the rate listed in the District database.

District Source Number (MMbtu/hr)	Refinery ID Number	Daily Firing Limit (MMbtu/day)	Hourly Firing Rate
S3	U230/B201	1,488	62
S7	U231/B103	1,536	64
S21	U244/B507	194.4	8.1

[Regulation 2-1-234.3]

1b. Each heater listed below shall not exceed the indicated daily firing rate limit (based on higher heating value of fuel), which are considered maximum sustainable firing rates. The indicated hourly firing rate is the daily limit divided by 24 hours and is the basis for permit fees and is the rate listed in the District database.

District Source Number	Refinery ID Number	Daily Firing Limit (MM BTU/day)	Hourly Firing Rate (MM BTU/hr)
S2	U229/B301	528	22
S4	U231/B101	2,304	96
S5	U231/B102	2,496	104
S8	U240/B1	6,144	256
S8 will be removed from service within 90 days of the date that the NOx offsets pursuant to Application 13424 must be supplied pursuant to BAAQMD Regulation 2-2-410.			
S9	U240/B2	1,464	61
S10	U240/B101	5,352	223

S11	U240/B201	2,592	108
S12	U240/B202	1,008	42
S13	U240/B301	4,656	194
S14	U240/B401	13,344	556
S15 thru S19	U244/B501 thru B505	5,754	239.75
S20	U244/B506	552	23
S22	U248/B606	744	31
S29	U200/B5	2,472	103
S30	U200/B101	1,200	50
S31	U200/B501	480	20
S43	U200/B202	5,520	230
S44	U200/B201	1,104	46
S351	U267	2,280	95
S336	U231/B104	2,664	111
S337	U231/B105	816	34
S371/372	U228/B520 and B521	1,392	58

[Regulation 2-1-301]

1c. Each heater listed below shall not exceed the indicated daily firing rate limit (based on higher heating value of fuel), which are considered maximum sustainable firing rates. The indicated hourly firing rate is the daily limit divided by 24 hours and is the basis for permit fees and is the rate listed in the District database.

District Source Number	Refinery ID Number	Daily Firing Limit (MMbtu/day)	Hourly Firing Rate (MMbtu/hr)
S438	U110	6,000	250

[Cumulative Increase]

2a. All sources shall use only refinery fuel gas and natural gas as fuel, EXCEPT for S438 which may also use pressure swing adsorption (PSA) off gas as fuel, and EXCEPT for S3 and S7 which may also use naphtha fuel.
[Regulation 9-1-304 (sulfur content), Regulation 2, Rule 1]

[Note: Part 2a will be amended by Application 12931, which will prohibit the use of liquid fuel at S3 and S7 except during periods of natural gas curtailment, test runs, or for operator training.]

2b. Sources S3 and S7 are permitted to use naphtha fuel. These sources shall be monitored for visible emissions during tube cleaning. If any visible emissions are detected when the operation commences, corrective action shall be taken within one day, and monitoring shall be performed after the corrective action is taken. If no visible emissions are detected, monitoring shall be performed on an hourly basis. [Regulation 2-6-409.2]

[Note: Part 2b will be amended by Application 12931, which will prohibit the use of liquid fuel at S3 and S7 except during periods of natural gas curtailment, test runs, or for operator training.]

2c. Sources S3 and S7 are permitted to use naphtha fuel. These sources shall be monitored for visible emissions before each 1 million gallons of liquid fuel is combusted at each source. If an inspection documents visible emissions, a Method 9 evaluation shall be completed within 3 working days, or during the next scheduled operating period if the specific unit ceases firing on liquid fuel within the 3 working day time frame. [Regulation 2-6-409.2].

[Note: Part 2c will be amended by Application 12931, which will prohibit the use of liquid fuel at S3 and S7 except during periods of natural gas curtailment, test runs, or for operator training.]

3a. The refinery fuel gas shall be tested for 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. As an alternative to GC TRS analysis, the fuel gas total sulfur content may be measured with a dedicated total sulfur analyzer (Houston Atlas or equivalent), and TRS concentration estimated based on the total sulfur/TRS ratio, with the TRS estimate increased by a 5% margin for conservatism. The total sulfur/TRS ratio shall be determined at least on a monthly basis through GC analyses of total sulfur and TRS values, and the most recent ratio shall be used to estimate TRS concentration. [SO2 Bubble]

3b. The average of the 3 daily refinery fuel gas TRS sample results shall be reported to the District in a table format each calendar month, with a separate entry for each daily average. Sample reports shall be submitted to the District within 30 days of the end of each calendar month. Any omitted sample results shall be explained in this report. [SO2 Bubble]

4. Emissions of SO2 shall not exceed 1,612 lb/day on a monthly average basis from non-cogeneration sources burning fuel gas or liquid fuel. This limit shall not include S45, Heater (U240) and shall not include any engine. [SO2 Bubble]

5. The following records shall be maintained in a District-approved log for at least 5 years and shall be made available to the District upon request:

a. Daily and monthly records of the type and amount of fuel combusted at each source listed in Part A.1. [Regulation 2, Rule 1]
b. TRS sample results as required by Part A.3 [SO2 Bubble]
c. SO2 emissions as required by Part A.4 [SO2 Bubble]
d. The operator shall keep records of all visible emission monitoring required by Part 2b, shall identify the person performing the monitoring and shall describe all corrective actions taken [Regulation 2-6-409.2]
e. The operator shall keep records of all visible emission monitoring required by Part 2c, of the results of required visual monitoring and Method 9 evaluations on these sources, shall identify the person performing the monitoring and shall describe all corrective actions taken. [Regulation 2-6-409.2]

F. S2, S3, S4, S5, S7, S8, S9, S10, S11, S12, S13, S14, Heaters

[S8 will be deleted from this part when the source is removed from service pursuant to Application 13424.]

1a. Total fuel firing at Unit 240 (S8, S9, S10, S11, S12, S13, S14) shall not exceed 993 MMbtu/hr averaged over any consecutive 12 month period. [Cumulative Increase]

[Part 1a will be effective until S8 is removed from service pursuant to Application 13424.]

1b. Total fuel firing at Unit 240 (S9, S10, S11, S12, S13, S14) shall not exceed 877.3 MMbtu/hr (based on higher heating value) averaged over any consecutive 12 month period. [Cumulative Increase]

[Part 1b will be effective after S8 is removed from service pursuant to Application 13424.]

2. Total fuel fired at the MP-30 Complex, including Unit 229 (S2), Unit 230 (S3) and Unit 231 (S4, S5, S7) shall not exceed 346.5 MMbtu/hr (based on higher heating value) averaged over any consecutive 12 month period. [Cumulative Increase]

3. Monthly records of the fuel fired at sources in Parts 1 and 2 shall be kept in a District-approved log for at least 5 years and shall be made available the District upon request. [Cumulative Increase]

G. Regulation 9-10 Startup / Shutdown Provisions [Basis: 9-10-301]

For determining compliance with Regulation 9-10-301, the contribution of each affected unit that is in a startup or shutdown condition shall be based on the methods described in 9-10-301.1, and the contribution of each affected unit that is in an out of service condition shall be based on the methods described in 9-10-301.2. Low-firing conditions (no higher than 20% of a unit's rated capacity), including refractory dryout periods, shall be considered out of service conditions subject to the 30-day averaging procedure in Regulation 9-10-301.2, including the 60-day annual limit for this procedure.

1. Heaters S8 (Unit 240, B-1), S14 (Unit 240, B-401) and S44 (Unit 200, B-201) shall be considered to be in normal operation whenever they have detectable fuel flow, and shall be considered to be out of service for the purpose of Regulation 9-10-301 whenever they have undetectable fuel flow.

[S8 will be deleted from this part when the source is removed from service pursuant to Application 13424.]

2. For heaters S43 (Unit 200, B-202), S351 (Unit 267, B-601/602) and S371/372 (Unit 228, B-520/521), the durations of startups, shutdowns and refractory dryout periods are defined in Condition 1694, Part D.2 (S43), Part B.2 (S351) and Part C.2 (S371, S372).

3. For heaters S10 (Unit 240, B-101) and S15 through S19 (Unit 244, B-501 through B-505), the duration of startups, shutdowns and low-firing periods are defined as follows:

a. startup and shutdown periods are not to exceed 24 hours
b. low-firing periods are not to exceed 72 hours

4. For heater S13 (Unit 240, B-301), the duration of startups, shutdowns and low-firing periods are defined as follows:

   a. startup and shutdown periods are not to exceed 72 hours
   b. low-firing periods are not to exceed 72 hours

5. For heaters with no CEMS:

   S2 (Unit 229, B-301)
   S3 (Unit 230, B-201)
   S4 (Unit 231, B-101)
   S5 (Unit 231, B-102)
   S7 (Unit 231, B-103)
   S9 (Unit 240, B-2)
   S11 (Unit 240, B-201)
   S12 (Unit 240, B-202)
   S20 (Unit 244, B-506)
   S22 (Unit 248, B-606)
   S29 (Unit 200, B-5)
   S30 (Unit 200, B-101)
   S31 (Unit 200, B-501)
   S336 (Unit 231, B-104)
   S337 (Unit 231, B-105)

   startups, shutdowns, and out of service conditions shall each not exceed 5 days in succession at each source.

Since ConocoPhillips has stated that the any additional HGO that they receive from their Santa Maria refinery will be transported by pipeline, a condition has been added to limit receipts of HGO destined for the hydrocracker through the wharf based on the average of the following 3 years: 8/1/02 to 8/1/05. The purpose of the condition is to ensure that emissions from marine vessels do not increase due to the CFEP project, as they have stated. If at a later date, ConocoPhillips wishes to receive more Santa Maria HGO by ship or purchase it from another source and receive it at the wharf, the facility may apply for this change and provide the emissions offsets.

CONDITION 4336
CONDITIONS FOR S425, S426**,** Marine Loading Berths

1. For each loading event of "regulated organic liquid", A420 shall be operated with a temperature of at least 1300 degrees F during the first 15 minutes of the loading operation. After the initial 15 minutes of loading, the A420 temperature shall be at least 1400 degrees F.
   [Cumulative Increase]

2. Instruments shall be installed and maintained to monitor and record the following:

a. Static pressure developed in the marine tank vessel
b. A420 temperature.
c. Hydrocarbons and flow to determine mass emissions or a concentration measurement alone if it is demonstrated to the satisfaction of the APCO that concentration alone allows verification of compliance, or
d. Any other device that verifies compliance, with prior approval from the APCO.

[Cumulative Increase]

3. A "regulated organic liquid" shall not be loaded from this facility into a marine tank vessel within the District whenever A420 is not fully operational. A420 must be maintained to be leak free, gas tight, and in good working order. For the purposes of this condition, "operational" shall mean the system is achieving the reductions required by Regulation 8, Rule 44; "regulated organic liquids" include gasoline, gasoline blendstocks, aviation gasoline and JP-4 aviation fuel and crude oil. [Cumulative Increase]

4. A leak test shall be conducted on all vessels loading under positive pressure prior to loading more than 20% of the cargo. The leak test shall include all vessel relief valves, hatch cover, butterworth plates, gauging connections, and any other potential leak points.

[Cumulative Increase]

5. Loading pressure shall not exceed 80% of the lowest relief valve set pressure of the vessel being loaded. [Cumulative Increase]

6a. No more than 25,000 barrels per day of gasoline, naphtha and C5/C6 shall be shipped across the wharf on an annual average basis. [Cumulative Increase]

1. Deleted Application 13690

2. ~~When barges are used to lighter crude oil, the volume of oil lightered during any reporting period shall be multiplied by a factor of 0.42 and included in the shipping totals to determine compliance with the throughput limits. The vessel Exxon Galveston is considered a ship for the purposes of this condition.~~

6b. The maximum loading rate at any time at both S425 and S426 shall not exceed 20,000 barrels per hour to prevent overloading the A420 oxidizer. [Cumulative Increase]

7a. The owner/operator shall not receive more than 30,000 bbl per day crude oil delivered by tanker or ship on a 12 month rolling average basis. (Cumulative increase, 2-1-403)

7b. The owner/operator shall receive no more than 249,000 barrels per year of gas oil feed at the Marine Terminal (S425, S426) to the U-240 (S305) Prefractionator. [Offsets]

8. ~~All throughput records required to verify compliance with Parts 6 and 7, including hourly loading rate records (total for S425, S426), monthly crude oil receipt records, and maintenance records required for A420, which are subject to Regulation 8, Rule 44, shall be kept on site for at least 5 years and made available to the District upon request. [Cumulative Increase]~~

9. ~~The destruction efficiency of the A420 control system shall be at least 98.5% by weight over each loading event for gasoline, gasoline blending stocks, aviation gas, aviation fuel (JP-4 type), and crude oil. [BACT]~~

10. The purpose of part 10 is to implement an alternative monitoring plan to assure compliance with the H2S limit in 40 CFR 60.104(a)(1) at A420, Thermal Oxidizer. This part will apply whenever A420 is used to comply with BAAQMD Regulation 8, Rule 44, and whenever A420 is used to burn fuel gas as defined by 40 CFR 60.101(d). To ensure that the thermal oxidizer is not used to burn fuel gas that is high in H2S, the following activities are not allowed at the terminal: ballasting, cleaning, inerting, purging, and gas freeing. The owner/operator shall perform the following monitoring: One detection tube sampling shall be conducted on the vapors collected during the event for each marine vessel tank that is affected. The detector tube ranges shall be 0-10/0-100 ppm (N=10/1) unless the H2S level is above 100 ppm. If the H2S level is above 100 ppm, the owner/operator shall use a detection tube with a 0-500 ppm range. The owner/operator shall use ASTM Method 4913-00, Standard Practice for Determining Concentration of Hydrogen Sulfide by Reading Length of Stain, Visual Chemical Detectors. The owner/operator shall maintain records of the H2S detection tube test data for five years from the date of the record. In addition, the owner/operator shall monitor at least once every calendar day that the thermal oxidizer is used. Within 8 months of approval of this part pursuant to Application 13691, the owner/operator shall submit the first six months of results of the H2S analysis to the District's Engineering and Enforcement and Compliance Departments for review.
[40 CFR 60.13(i), BAAQMD Regulation 2-6-501]

The purpose of Condition 6671 is to control emissions of POC from the dearator vent of a hydrogen plant that serves S307, Unicracker. Since hydrogen plants are normally permitted separately, a new source designation has been created for the hydrogen plant, and the condition has been assigned to it.

CONDITION 6671

CONDITIONS FOR S464, HYDROGEN PLANT, U-240 PLANT 4

1. The vapor vent on the E-421 condenser (overhead condenser on D-406 condensate stripper in U-240 Unicracker Complex hydrogen plant) shall be vented to the A50 (D-410 Vent Scrubber) condenser whenever the vent operates. [Regulation 8-2-301]

2. A50 shall reduce total organic carbon emissions from the E-421 vent as necessary to a level that complies with Regulation 8-2-301. [Regulation 8-2-301]

3. All blowdown and other liquid effluent from A50 shall be piped to the plant wastewater treatment system. [Cumulative Increase]

4. Whenever the U-240 hydrogen plant operates, normal flow of scrubbing liquid through the E-421 scrubber pumparound pump and normal flow of cooling water through the pumparound cooler shall be verified on a daily basis. [Cumulative Increase]

5. Daily records (on days when the U-240 hydrogen plant operates) of normal scrubbing liquid flow and normal cooling water flow shall be kept in a District-approved log for at least five years and shall be made available to the District upon request. [Cumulative Increase]

6. Effective 1/1/05, an annual source test shall be performed on the vapor vent on the E-421 condenser to verify compliance with Regulation 8-2-301 in accordance with District source test methods or other methods approved in advance by the District. A copy of the test report shall be provided to the District Director of Compliance and Enforcement within 45 days of completion of the test. [Regulation 2-6-409.2]

CONDITION 6725

CONDITIONS FOR S432, DEISOBUTANIZER

1. All new flanges in hydrocarbon service associated with the S432 Deisobutanizer project shall utilize graphitic gaskets. All new valves in hydrocarbon service associated with the project shall be either live-loaded valves, bellows-sealed valves, diaphragm valves, or other District approved equivalent valve designs. [BACT, Cumulative Increase]

2. All new pressure relief valves in hydrocarbon service associated with the S432 project shall be vented to the refinery flare gas recovery system. [BACT, Cumulative Increase]

3. All new pumps and compressors in hydrocarbon service associated with the S432 project shall utilize either a double mechanical shaft seal design with barrier fluid, a magnetically coupled shaft, or other District approved equivalent design. If a barrier fluid is used, either the fluid reservoir shall be vented to a 95% efficient control device, or the barrier fluid shall be operated at a pressure higher than the process stream pressure. [BACT, Cumulative Increase]

4. The owner/operator shall ensure that the throughput of S432 does not exceed 10,200 barrels/day. [Cumulative Increase]

5. All pressure relief devices on the process unit shall be vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. [8-28-302, BACT]

Parts 6, 15, and 9 of Condition 12122 imply the presence of fuel meters for these sources. Part 9d was added to make this clear.

Part 9b of Condition 12122 was amended after public comment to make clear that control of emissions at the turbines and duct burners are required when NOx emissions must be reduced to provide offsets for Application 13424 in accordance with offset condition 22970, part B.

CONDITION 12122

CONDITIONS FOR S352, S353, S354, S355, S356, S357: TURBINES AND DUCT BURNERS

1. The gas turbines (S352, S353 and S354) and the heat recovery steam generator (HRSG) duct burners (S355,S356 and S357) shall be fired on refinery fuel gas or natural gas.
[Cumulative Increase]

2. A HRSG duct burner shall be operated only when the associated gas turbine is operated.
[Cumulative Increase]

3. The exhaust from S352 and S355 shall be abated at all times by SCR unit A13, except that S352 and S355 may operate without SCR abatement on a temporary basis for periods of planned or emergency maintenance. A District-approved NOx CEM shall monitor and record the 352 and S355 NOx emission rate whenever S352 and S355 operate without abatement. All emission limits applicable to S352 and S355 shall remain in effect whether or not they are operated with SCR abatement.
[BACT, Cumulative Increase]

4. The exhaust from S353 and S356 shall be abated at all times by SCR unit A14, except that S353 and S356 may operate without SCR abatement on a temporary basis for periods of planned or emergency maintenance. A District-approved NOx CEM shall monitor and record the S353 and S356 NOx emission rate whenever S353 and S356 operate without abatement. All emission limits applicable to S353 and S356 shall remain in effect whether or not they are operated with SCR abatement.
[BACT, Cumulative Increase]

5. The exhaust from S354 and S357 shall be abated at all times by SCR unit A15, except that S354 and S357 may operate without SCR abatement on a temporary basis for periods of planned or emergency maintenance. A District-approved NOx CEM shall monitor and record the S354 and S357 NOx emission rate whenever S354 and S357 operate without abatement.

All emission limits applicable to S354 and S357 shall remain in effect whether or not they are operated with SCR abatement. [BACT, Cumulative Increase]

6. Total fuel fired in S355, S356, and S357 shall not exceed 2.42 E 12 btu in any consecutive 365 day period. [Cumulative Increase]

7. CO emissions from each turbine/duct burner set shall not exceed 39 ppmv at 15% oxygen, averaged over any consecutive 30 day period. Emissions during startup periods, which shall not exceed four hours, and shutdown periods, which shall not exceed two hours, may be excluded when averaging emissions. [BACT, Cumulative Increase]

8. POC emissions from each turbine/duct burner set shall not exceed 6 ppmv at 15% oxygen, averaged over any consecutive 30 day period. Emissions during startup periods, which shall not exceed four hours, and shutdown periods, which shall not exceed two hours, may be excluded when averaging emissions. [BACT, Cumulative Increase]

9a. The combined NOx emissions from S352, S353, S354, S355, S356 and S357 shall not exceed 66 lb/hr (averaged over any 3 hour period), nor 167 tons in any consecutive 365 day period. NOx emissions from each turbine/duct burner set shall not exceed 528 lb/day. (This condition will be invalid when the NOx emissions at these sources must be reduced to provide offsets for Application 13424.) [BACT, Cumulative Increase]

9b. This part will apply after NOx emissions at S352, S353, S354, S355, S356 and S357 must be reduced to provide offsets for Application 13424 per Condition 22970, Part B. The combined NOx emissions from S352, S353, S354, S355, S356 and S357 shall not exceed 66 lb/hr (averaged over any 3 hour period), and shall not exceed 79.8 tons in any consecutive 365 day period. NOx emissions from each turbine/duct burner set shall not exceed 528 lb/day. [BACT, Cumulative Increase]

9c. NOx emissions from S 352, S353, S354, S355, S356 and S357 shall be monitored with a District-approved continuous emission monitor. [BACT, Cumulative Increase]

9d. The owner/operator shall use a fuel meter to determine the heat input to each unit. This data shall be used to determine compliance with all throughput limits and the NOx, CO, and SO2 mass emission limits. [Cumulative Increase, 2-6-503]

10a. The combined CO emissions from S352, S353, S354, S 355, S356 and S357 shall not exceed 200 tons in any consecutive 365 day period. [BACT, Cumulative Increase]

10b. CO emissions from S 352, S353, S354, S355, S356 and S357 shall be monitored with a District-approved continuous emission monitor. [BACT, Cumulative Increase]

11. The combined POC emissions S352, S353, S354, S355, S356 and S357 shall not exceed 8.3 lb/hr and shall not exceed 30.5 tons in any consecutive 365 day period.
[BACT, Cumulative Increase]

12. The refinery fuel gas shall be tested for total reduced sulfur (TRS) concentration 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.
[Cumulative Increase]

13. The average of the 3 daily refinery fuel gas TRS sample results shall be reported to the District in a table format each calendar month, with a separate entry for each daily average. Sample reports shall be submitted to the District within 30 days of the end of each calendar month. Any omitted sample results shall be explained in this report.
[Cumulative Increase]

14. A source test to verify compliance with Parts 8 and 11 shall be performed each calendar year in accordance with District source test methods or other methods approved in advance by the District. A copy of the test report shall be provided to the District Director of Compliance and Enforcement within 45 days of completion of the test. [Regulation 2-6-409.2]

15. Records shall be maintained to allow verification of compliance with all permit conditions. Records shall be retained for at least five years and shall be made available to the District upon request. [BACT, Cumulative Increase]

CONDITION 13184
For Source S182

1. The POC emissions from the S182 fixed roof storage tank shall be collected and vented at all times to the fuel gas collection system.
[Cumulative Increase]

Condition 18629 is a PSD condition that was originally imposed by EPA. It also applies to the turbines. The existence of a fuel meter is implied in parts XI.G.1.b and XI.G.3.a(2).

CONDITION 18629
Conditions for S352, S353, S354, S355, S356, S357

May 30, 1989 PSD Permit Amendments (first issued March 3, 1986)
Permit NSR 4-4-3 SFB 85-03

I. [Obsolete – Approval to Construct executed in a timely manner]

II. [Obsolete – Approval to Construct executed in a timely manner]

III. Facilities Operation

All equipment, facilities and systems installed or used to achieve compliance with the terms and conditions of this Approval to Construct/Modify shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions.

IV. Malfunction

The Regional Administrator shall be notified by telephone within two working days following any failure of air pollution control equipment, process equipment, or of any process to operate in a normal manner which results in an increase in emissions above any allowable emissions limit stated in Section IX of these conditions. In addition, the Regional Administrator shall be notified in writing within 15 days of any such failure. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial failure, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed under Section IX of these conditions, and the methods utilized to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of this permit or of any law or regulations that such malfunction may cause.

V. Right to Entry

The Regional Administrator, the head of the State Air Pollution Control Agency, the head of the responsible local air pollution control agency, and/or their authorized representatives, upon presentation of credentials, shall be permitted:

A. to enter upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this Approval to Construct/Modify; and

B. at reasonable times to have access to and copy any records required to be kept under the terms and conditions of this Approval to Construct/Modify; and

C. to inspect any equipment, operation, or method required in this Approval to Construct/Modify; and

D. to sample emissions from this source.

VI. Transfer of Ownership

In the event of any changes in control or ownership of facilities to be constructed or modified, this Approval to Construct/Modify shall be binding on all subsequent owners and operators. The applicant shall notify the succeeding owner and operator of the existence of this Approval to Construct/Modify and its conditions by letter, a copy of which shall be forwarded to the Regional Administrator and the State and local Air Pollution Control Agency.

VII. Severability

The provisions of this Approval to Construct/Modify are severable, and, if any provisions of this Approval to Construct/Modify are held invalid, the remainder of this Approval to Construct/Modify shall not be affected thereby.

VIII. Other Applicable Regulations

The owner and operator of the proposed project shall construct and operate the proposed stationary source in compliance with all other applicable provisions of Parts 52, 60 and 61 and all other applicable Federal, State and local air quality regulations.

IX. Special Conditions

A. [Obsolete – Approval to Construct executed in a timely manner]

B. Air Pollution Control Equipment
The owner/operator shall install, continuously operate, and maintain the following air pollution controls to minimize emissions. Controls listed shall be fully operational upon startup of the proposed equipment.

1. Each gas turbine shall be equipped with steam injection for the control of NOx emissions.

2. Each gas turbine shall be equipped with a Selective Catalytic Reduction (SCR) system for the control of NOx emissions.

D. Operating Limitations

1. The gas turbines and Heat Recovery Steam Generator (HRG) burners shall be fired only on refinery fuel gas and natural gas

2. The firing rate of each gas turbine/HRG burner set shall not exceed 466 MMbtu/hr.

3. The total fuel firing rate of the Steam/Power Plant shall not exceed 1048 MMbtu/hr.

4. The owner/operator shall maintain records of the amount of fuel used in the gas turbines and the HRG Burners, hours of operation, sulfur content of the fuel, and the ratio of steam injected to fuel fired in each gas turbine, in a permanent form suitable for inspection. The record shall be retained for at

least two years following the date of record and shall be made available to EPA upon request.

E. Emission Limits for NOx

On or after the date of startup, the owner/operator shall not discharge from the gas turbine/HRG Burner sets NOx in excess of the more stringent of 83 lb/hr total or 25 ppmv at 15% O2 (3-hour average), or 664 lb/day per set. The concentration limit shall not apply for 4 hours during startup or 2 hours during shutdown.

F. Emission Limits for SO2

On or after the date of startup, the owner/operator shall not discharge from the gas turbine/HRG Burner sets SO2 in excess of 15.6 lb/hr per set or 44 lb/hr total (3-hour average). Additionally, total SO2 emissions shall not exceed 34 lb/hr (3 hour average) for more than 36 days per year, and shall not exceed a total of 153 tons per year (365 days)

G. Continuous Emission Monitoring

1. Prior to the date of startup and thereafter, the owner/operator shall install, maintain and operate the following continuous monitoring systems downstream of each of the gas turbine/HRG Burner units:

a. Continuous monitoring systems to measure stack gas NOx and SO2 concentrations. The systems shall meet EPA monitoring performance specifications (60.13 and 60, Appendix B, Performance Specifications). Alternatively, the SO2 continuous monitor may be substituted for by a continuous monitoring system measuring H2S in the refinery fuel gas system and daily sampling for total sulfur in the fuel gas.

b. A system to calculate the stack gas volumetric flow rates continuously from actual process variables.

2. The owner/operator shall maintain a file of all measurements, including continuous monitoring system performance evaluations, all continuous monitoring system monitoring device calibration checks, adjustments and maintenance performed on these systems or devices, and all other information required by 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports and records.

3. The owner/operator shall submit a written report of SO2 emission status and all excess emissions to EPA (Attn: A3-3) for every calendar quarter. The report shall include the following:

a. If fuel gas samples are used to determine SO2 emissions:
(1) The total measured sulfur concentration in each fuel gas sample for the calendar quarter.

(2) The daily average sulfur content in the fuel gas, daily average SO2 mass emission rate (lb/hr), and total tons per year of SO2 emitted for the last 365 consecutive days. Total SO2 emissions exceeding 34 lb/hr must be identified.

b. The magnitude of excess emissions computed in accordance with 60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

c. Specific identification of each period of excess emissions that occurs during startups, shutdowns and malfunctions of the cogeneration gas turbine system. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted shall also be reported.

d. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments.

e. When no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

f. Excess emissions shall be defined as any three-hour period during which the average emissions of NOx and/or SO2 as measured by the continuous monitoring system and/or calculated from the daily average of the total sulfur in the fuel gas, exceeds the NOx and/or SO2 maximum emission limits set for each of the pollutants in Conditions IX.E and IX.F. above

g. Excess emissions indicated by the CEM system shall be considered violations of the applicable emission limits for the purpose of this permit.

H. New Source Performance Standards

The proposed cogeneration facility is subject to the Federal regulations entitled Standards of Performance for New Stationary Sources (60). The owner/operator shall meet all applicable requirements of Subparts A and GG of this regulation.

X. Agency Notifications

All correspondence as required by this Approval to Construct/Modify shall be forwarded to:

A. Director, Air Management Division (Attn: A3-3)
EPA Region 9
215 Fremont Street
San Francisco, CA 94105 (415/974-8034)

B. Chief, Stationary Source Division
California Air Resources Board
P O Box 2815

Sacramento, CA 95812

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

The throughput limits for S1001-S1003 were established in Application 5814, but were not added to the permit condition.

CONDITION 19278

Conditions for S1001, S1002, S1003

1. Deleted Application 12433

2. Deleted Application 12433

3. An annual District-approved source test shall be performed to verify compliance with the requirements of Regulation 6-330. A copy of the source test results shall be provided to the District Director of Compliance and Enforcement within 45 days of the test.
[Regulation 6-330]

4. The Owner/Operator shall perform a visible emissions check on Sources S1001, S1002, and S1003 on a monthly basis. The visible emissions check shall take place while the equipment is operating and during daylight hours. If any visible emissions are detected, the owner/operator shall have a CARB-certified smoke reader determine compliance with the opacity standard, using EPA Method 9 or the procedures outlined in the CARB manual, “Visible Emissions Evaluation” for six (6) minutes within three (3) days and record the results of the reading. If the reading is in compliance with the Ringelmann 1.0 limit in BAAQMD Regulation 6-301, the reading shall be recorded and the owner/operator shall continue to perform a visible emissions check on a monthly basis. If the reading is not in compliance with the Ringelmann 1.0 limit in BAAQMD Regulation 6-301, the owner/operator shall take corrective action and report the violation in accordance with Standard Condition 1.F of this permit. The certified smoke-reader shall continue to conduct the Method 9 or CARB Visible Emission Evaluation on a daily basis until the daily reading shows compliance with the applicable limit or until the equipment is shut down. Records of visible emissions checks and opacity readings made by a CARB-certified smoke reader shall be kept for a period of at least 5 years from date of entry and shall be made available to District staff upon request.
[Basis: Regulations 6-301, 2-6-501, 2-6-503]

5. The owner/operator shall ensure that the throughput of molten sulfur at S1001, S1002, and S1003 combined does not exceed 98,915 long tons/yr.
[Cumulative Increase]

CONDITION 20773

This condition applies to tanks that are exempt from Regulation 8, Rule 5, Storage of Organic Liquids, due to the exemption in Regulation 8-5-117 for storage of organic liquids with a true vapor pressure of less than or equal to 25.8 mm Hg (0.5 psia).

1. Whenever the type of organic liquid in the tank is changed, the owner/operator shall verify that the true vapor pressure at the storage temperature is less than or equal to 25.8 mm Hg (0.5 psia). The owner/operator shall use Lab Method 28 from Volume III of the District's Manual of Procedures, Determination of the Vapor Pressure of Organic Liquids from Storage Tanks. For materials listed in Table 1 of Regulation 8 Rule 5, the owner/operator may use Table 1 to determine vapor pressure, rather than Lab Method 28. If the results are above 25.8 mm Hg (0.5 psia), the owner/operator shall report non-compliance in accordance with Standard Condition I.F and shall submit an application to the District for a new permit to operate for the tank as quickly as possible. [Basis: 8-5-117 and 2-6-409.2]

2. The results of the testing shall be maintained in a District-approved log for at least five years from the date of the record, and shall be made available to District staff upon request.
[Basis: 2-6-409.2]

Following is an excerpt of Condition 20989, which contains nominal throughputs for grandfathered sources. Several sources, which will have new limits, will be deleted from this condition. The new limits will appear in new conditions.

The limits for S301-S303, Sulfur Pits, and S1001-S1003, Sulfur Recovery Units, are not grandfathered limits, since these limits were increased in Application 5814. The limits for S301-S303 have been moved to Condition 22964 and the conditions for S1001-S1003 have been moved to Condition 19278.

FACILITY-WIDE REQUIREMENTS
CONDITION 20989

A. THROUGHPUT LIMITS

The following limits are imposed through this permit in accordance with Regulation 2-1-234.3. Sources require BOTH hourly/daily and annual throughput limits (except for tanks and similar liquid storage sources, and small manually operated sources such as cold cleaners which require only annual limits). Sources with previously imposed hourly/daily AND annual throughput limits are not listed below; the applicable limits are given in the specific permit conditions listed above in this section of the permit. Also, where hourly/daily capacities are listed in Table II-A, these are considered enforceable limits for sources that have a New Source Review permit. Throughput limits imposed in this section and hourly/daily capacities listed in Table II-A are not federally enforceable for grandfathered sources. Grandfathered sources are indicated with an asterisk in the source number column in the following table. Refer to Title V Standard Condition J for clarification of these limits.

In the absence of specific recordkeeping requirements imposed as permit conditions, monthly throughput records shall be maintained for each source.

source number	hourly / daily throughput limit	annual throughput limit (any consecutive 12-month period unless otherwise specified)
~~*118~~	~~NA for tank~~	~~15,000 bbl~~
~~*122~~	~~NA for tank~~	~~4.38 E 6 bbl~~
~~*128~~	~~NA for tank~~	~~5.1 E 6 bbl~~
~~*139~~	~~NA for tank~~	~~2.74 E 6 bbl~~
~~*140~~	~~NA for tank~~	~~2.74 E 6 bbl~~
~~301~~	~~Table II-A~~	~~98,915 long ton for S301, S302, S303~~
~~302~~	~~Table II-A~~	~~98,915 long ton for S301, S302, S303~~
~~303~~	~~Table II-A~~	~~98,915 long ton for S301, S302, S303~~
~~307~~	~~Table II-A~~	~~1.533 E 7 bbl~~
~~*308~~	~~Table II-A~~	~~5.87 E 6 bbl~~
~~*309~~	~~Table II-A~~	~~6.11 E 6 bbl~~
~~*318~~	~~Table II-A~~	~~3.3 E 7 bbl~~
~~*339~~	~~Table II-A~~	~~5.26 E 7 bbl~~
~~432~~	~~Table II-A~~	~~2.8 E6 bbl~~
~~1001~~	~~Table II-A~~	~~98,915 long ton for S1001, S1002, S1003~~
~~1002~~	~~Table II-A~~	~~98,915 long ton for S1001, S1002, S1003~~
~~1003~~	~~Table II-A~~	~~98,915 long ton for S1001, S1002, S1003~~

In the original proposal, the conditions for new fugitive components were included with the condition for fugitive components for the ULSD project in 2002. A new BACT determination was made after public notice. Condition 21099 will no longer apply to the new components. Condition 23725 replaces this condition for those components.

CONDITION 21099

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; Regulation 2, Rule 5]

An excerpt of Condition 21235 (NOx box condition) is shown below.

CONDITION 21235

REGULATION 9-10 COMPLIANCE
CONDITIONS FOR SOURCES S2, S3, S4, S5, S7, S8, S9, S10, S11, S12, S13, S14, S15, S16, S17, S18, S19, S20, S22, S29, S30, S31, S43, S44, S336, S337, S351, S371, S372

1. The following sources are subject to the refinery-wide NOx emission rate and CO concentration limits in Regulation 9-10: [Regulation 9-10-301 and 305]

S#	Description	NOx CEM
2	U229, B-301 Heater	No
3	U230, B-201 Heater	No

4	U231, B-101 Heater		No
5	U231, B-102 Heater		No
7	U231, B-103 Heater		No
8	U240, B-1 Boiler	Yes	

S8 will be removed from service within 90 days of the date that the NOx offsets pursuant to Application 13424 must be supplied pursuant to BAAQMD Regulation 2-2-410.

9	U240, B-2 Boiler	No	
10	U240, B-101 Heater		Yes
11	U240, B-201 Heater		No
12	U240, B-202 Heater		No
13	U240, B-301 Heater		Yes
14	U240, B-401 Heater		Yes
15	U244, B-501 Heater		Yes
16	U244, B-502 Heater		Yes
17	U244, B-503 Heater		Yes
18	U244, B-504 Heater		Yes
19	U244, B-505 Heater		Yes
20	U244, B-506 Heater		No
22	U248, B-606 Heater		No
29	U200, B-5 Heater	No	
30	U200, B-101 Heater		No
31	U200, B-501 Heater		No
43	U200, B-202 Heater		Yes
44	U200, B-201 PCT Reboil Furnace	Yes	
336	U231 B-104 Heater	No	
337	U231 B-105 Heater	No	
351	U267 B-601/602 Tower Pre-Heaters		Yes
371	U228 B-520 (Adsorber Feed) Furnace		Yes
372	U228 B-521 (Hydrogen Plant) Furnace		Yes

CONDITION 22478

For Sources S123 (Tank 168), S124 (Tank 169), S186 (Tank 298), and S334 (Tank 107)

1. The owner/operator shall ensure that S123 contains only water and petroleum liquid with a true vapor pressure less than or equal to 3.0 psia. [Cumulative Increase]

2. The owner/operator shall ensure that S124 contains only water and petroleum liquid with a true vapor pressure less than or equal to 11.0 psia [Cumulative Increase]

3. The owner/operator shall ensure that the emissions of S186 do not exceed 2,231 lb VOC in any consecutive 12-month period. S186 shall only contain petroleum liquids. [Cumulative Increase]

4. The owner/operator shall ensure that S334 contains only crude oil or a less volatile petroleum liquid with a true vapor pressure less than or equal to 6.75 psia. [Cumulative Increase]

5. The owner/operator shall ensure that the throughput of petroleum liquids at S123 does not exceed 3,000,000 barrels/yr. [Cumulative Increase]

6. The owner/operator shall ensure that the throughput of petroleum liquids at S124 does not exceed 3,000,000 barrels/yr. [Cumulative Increase]

7. The owner/operator shall ensure that the throughput of crude oil or other petroleum liquids at S334 does not exceed 5,000,000 barrels/yr. [Cumulative Increase]

8. The owner/operator shall equip S123, S124, S186, and S334 with a BAAQMD approved roof with mechanical shoe primary seal and zero gap secondary seal meeting the design criteria of BAAQMD Regulation 8, Rule 5. The owner/operator shall ensure that there are no ungasketed roof penetrations, no slotted pipe guide poles unless equipped with float and wiper seals, and no adjustable roof legs unless fitted with vapor seal boots or equivalent. [BACT, cumulative increase]

9. The owner/operator shall calculate the emissions of S186 on a calendar month basis using the AP-42 equations. The owner/operator shall use actual throughputs, actual vapor pressures, and actual temperature data for each month. The owner/operator shall calculate the emissions for the last 12-month period on a monthly basis. The calculations shall be complete within a calendar month after the end of each monthly period. [Cumulative increase]

Condition 22549 has been amended so that the throughput limit excludes diesel because the diesel flow is an insignificant source of emissions at the tanks. The previous throughput limit of 33 MMbbl for all fluids has been deleted from Condition 20989, part A. The facility applied for this modification in Application 10115. It was not granted at that time because it results in an increase of gasoline flow to the tanks. In this application, the facility is applying for the increase in emissions at the tanks.

CONDITION 22549
Source 318, U76 Gasoline/Mid Barrel Blending Unit

1. The owner/operator shall ensure that the daily throughput of petroleum liquids, excluding diesel, at S318, U76 Gasoline/Mid Barrel Blending Unit, does not exceed 113,150 barrels/day. No daily limit is placed on diesel. [Cumulative Increase]

2. The owner/operator shall ensure that the throughput of petroleum liquids excluding diesel at S318 does not exceed 41,300,000 barrels/yr.

3. The owner/operator shall keep daily records of throughput of all petroleum fluids at S318, U76 Gasoline/Mid Barrel Blending Unit, in a District-approved log. These records shall be kept for at least five years and shall be made available to the District upon request. [Cumulative Increase]

4. All pressure relief devices on the process unit shall be vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. [8-28-302, BACT]

The NOx and CO limits is BAAQMD Condition 22962, parts 4a, b, and e, have been amended in response to new BACT determinations made at SCAQMD. The NOx limit has been reduced to 5 ppmv @ 3% O2, dry, 3-hour limit. The CO limit has been reduced to 10 ppmv @ 3% O2, dry, 3-hour limit, and 28 ppm @ 3% O2, 3-hour limit when operating under 30 MMbtu/hr. This heater will be operated as a trim heater for long periods of time. The lower CO limit is not feasible when operating under 30 MMbtu/hr. The hourly mass emissions will not increase. The ammonia limit in part 5 will increase to make it possible to achieve the 5 ppm NOx limit.

A basis of 40 CFR 63.52(a) has been added to the CO limits in parts 4b and 4e because, as explained in Section 5, Statement of Compliance, S45 is subject to a case-by-case MACT determination as a substitute for the standards in 40 CFR 63, Subpart DDDDD, which has been vacated. Also, part 18, which required compliance with the requirements of Subpart DDDDD, has been deleted.

The asterisk before part 5 is an indication that the condition is not federally enforceable. The reason that it is not federally enforceable is that it was imposed pursuant to BAAQMD Regulation 2, Rule 5, New Source Review for Toxic Air Contaminants, which is not a federally enforceable rule.

Part 9 of BAAQMD Condition 22962 was reorganized after public comment. The wording was also amended to make clear that the facility is not required to submit results of source tests if the District performed the tests.

CONDITION 22962
Source 45, U246 B-801/B-802 Heater

1. The owner/operator of the S45 heater shall fire only refinery fuel gas and/or natural gas at this unit. [BACT, Cumulative Increase]

2. Based on refinery gas HHV, the owner/operator of S45 shall not exceed the following firing rates:

   a. 85 MMbtu/hr
   b. 744,600 MMbtu in any consecutive 12-month period. [Cumulative Increase]

3. The owner/operator of S45 shall abate emissions from S45 at the A47 SCR system whenever S45 is operated, except that S45 may operate without SCR abatement on a temporary basis for periods of planned or emergency maintenance. A District-approved NOx CEM shall monitor and record the S45 NOx emission rate whenever S45 operates without abatement. All emission limits applicable to S45 shall remain in effect even if it is operated without SCR abatement. [BACT, Cumulative Increase]

4. The owner/operator of S45 shall not exceed the following emission concentrations or rates from S45/A47 except during startups and shutdowns. Startups and shutdowns shall not exceed 48 consecutive hours. The 48 consecutive-hour startup period is in addition to heater dryout/warmup periods, which shall not exceed 24 consecutive hours.

   a. NOx: 5 ppmv @ 3% oxygen (3 hr average) [BACT, Cumulative Increase]
   b. CO: 28 ppmv @ 3% oxygen (3 hr average) when operating under 30 MMbtu/hr [BACT, Cumulative Increase, 40 CFR 63.52(a)]
   c. POC: 5.5 lb/MM ft3 [Cumulative Increase]
   d. PM10: 7.6 lb/MM ft3 [BACT, Cumulative Increase]
   e. CO: 10 ppmv @ 3% oxygen (3 hr average) when operating over 30 MMbtu/hr [BACT, Cumulative Increase, 40 CFR 63.52(a)]

   If the heater operates at rates below and above 30 MMbtu/hr in any 3-hour period, the CO limit shall be a weighted average.

5. *The owner/operator of S45 shall not exceed the following emission rate from S45/A47 except during startups and shutdowns. Startups and shutdowns shall not exceed 48 consecutive hours. The 48 consecutive-hour startup period is in addition to heater dryout/warmup periods, which shall not exceed 24 consecutive hours.

   Ammonia: 15 ppmv @ 3% oxygen (8 hr average) [Regulation 2, Rule 5]

6. The owner/operator of S45 shall not exceed the following annual emission rates from S45/A47 including startups, shutdowns, and malfunctions.
   NOx: 2.3 tons/yr [BACT, Cumulative Increase]
   CO: 2.8 tons/yr [BACT, Cumulative Increase]
   POC: 1.5 tons/yr [Cumulative Increase]
   PM10: 2.1 tons/yr [BACT, Cumulative Increase]
   SO2: 4.7 tons/yr [BACT, Cumulative Increase]
   Year is defined as every consecutive 12-month period. Month is defined as calendar month.

7. The owner/operator shall equip S45 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]

8. The owner/operator shall install, calibrate, maintain, and operate District-approved continuous emission monitors and recorders 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]

9. The owner/operator shall conduct District-approved source tests two times per year to determine compliance with the CO limit. The tests shall be no

less than 4 months apart and no more than 8 months apart. The source tests shall be performed on the heater in an as-found condition. CO source tests performed by the District may be substituted for semi-annual CO source tests. If the heater exceeds the limits in parts 4b or 4e more than once in any 3-year period, the owner/operator shall install, calibrate, maintain, and operate a District-approved continuous emission monitor and recorder for CO within the time period specified in the District Manual of Procedures after the second exceedance of the limits in parts 4b or 4e. The owner/operator shall keep CO data for at least five years and shall make these records available to the District upon request.

For tests conducted by the owner/operator, the owner/operator shall conduct the source tests in accordance with Part 17. The owner/operator shall submit the source test results to the Director of Compliance and Enforcement, the Source Test Manager, and the Manager of Permit Evaluation at the District no later than 60 days after the source test. [BACT, Cumulative Increase]

10. The owner/operator shall use only refinery fuel gas and/or natural gas at S45 that does not exceed 100 ppmv total sulfur, averaged over a calendar month. [BACT, Cumulative Increase]

11. The owner/operator shall test refinery fuel gas prior to combustion at S45 to determine total sulfur concentration by GC analysis or with a total sulfur analyzer (Houston Atlas or equivalent) 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. [BACT, Cumulative Increase]

12. To demonstrate compliance with Part 10, the owner/operator shall measure and record the daily average sulfur content. The owner/operator shall keep records of sulfur content in fuel gas for at least five years and shall make these records available to the District upon request. [BACT, Cumulative Increase]

13. For the purpose of demonstrating compliance with the H2S limit in 40 CFR 60.104(a)(1), the owner/operator shall test refinery fuel gas prior to combustion at S45 to determine total H2S concentration 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. Records of H2S monitoring shall be kept for at least five years after the date the record was made. The owner/operator shall submit a semi-annual report regarding this monitoring to the District and to EPA. The reporting periods shall start on January 1st and July 1st of each year. The reports shall be submitted by January 31st and July 31st of each year. If the limit has not been exceeded during the reporting period, this information shall be stated in the report. If the limit has been exceeded, the owner/operator shall report the date and time that the exceedance began and the date and time that the exceedance ended. The owner/operator shall estimate and report the excess emissions during the exceedance. [40 CFR 60.13(i)]

14. The owner/operator shall record the duration of all startups, shutdowns, and heater dryout/warmup periods to determine compliance with parts 4 and 5. The owner/operator shall keep the records for at least five years and shall make these records available to the District upon request. [2-6-503]

15. Prior to the commencement of construction, the owner/operator shall submit plans to the District's Source Test Manager to obtain approval of the design and location of the source test ports. The sample ports shall be installed in accordance with Manual of Procedures, Volume 4, Section 1.2.4. (basis: Regulation 1-501)

16. No later than 90 days from the startup of S45, the owner/operator shall conduct District-approved source tests to determine initial compliance with the limits in Part 4 for NOx, CO, POC, PM10 and ammonia. For PM10, USEPA Methods 201 and 202 with the back-half ammonium sulfate subtracted, shall be used. The owner/operator shall conduct the source tests in accordance with Part 17. 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, Regulation 2, Rule 5]

17. The owner/operator shall comply with all applicable requirements for source tests specified in Volume IV of the District's Manual of Procedures and 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 Manager, in writing, of the source test protocols and projected test dates at least 7 days prior to testing. [BACT, Cumulative Increase, Regulation 2, Rule 5]

18. The owner/operator will ensure that S45, Heater, complies with all applicable provisions of 40 CFR 60, Subpart J. (This part will be deleted when the applicable citations from this standard are incorporated into the Major Facility Review permit.) [40 CFR 60, Subpart J]

CONDITION 22963
For Sources S98 (Tank 101), S118 (Tank 163), S122 (Tank 167), S128 (Tank 174), S139 (Tank 204); S140 (Tank 205)

1. The owner/operator shall ensure that the following tanks contain only petroleum liquids with true vapor pressures less than or equal the vapor pressures below.
   a. S98 10 psia
   b. S118 0.5 psia
   c. S122 11 psia
   d. S128 4.4 psia
   [Cumulative Increase]

2. The owner/operator shall ensure that the throughput of petroleum liquids at the following tanks do not exceed the following throughput limits.
   a. S98 7.446,000 barrels per consecutive 12-month period
   b. S118 900 barrels per consecutive 12-month period
   c. S122 2,000,000 barrels per consecutive 12-month period
   d. S128 5,100,000 per consecutive 12-month period
   [Cumulative Increase]

3. The owner/operator shall ensure that S139 and S140 are abated by A7, Vapor Recovery System. [8-5-301, 40 CFR 61, Subpart FF]

4. The owner/operator shall equip S98, S122, and S128 with a BAAQMD approved roof with mechanical shoe primary seal and zero gap secondary seal meeting the design criteria of BAAQMD Regulation 8, Rule 5. The owner/operator shall ensure that there are no ungasketed roof penetrations, no slotted pipe guide poles unless equipped with float and wiper seals, and no adjustable roof legs unless fitted with vapor seal boots or equivalent. [BACT, cumulative increase]

The throughput limits for S301, S302, and S303 were established in Application 5814, but were not added to the permit conditions. In the original application, S505, Sulfur Loading Rack, was abated by A424, Tail Gas Incinerator, but the facility has decided to abate it with S1004, Sulfur Recovery Unit.

CONDITION 22964
Sources S301, S302, S303, Sulfur Pits, S465, Sulfur Pit abated by S1004, Sulfur Recovery Unit

1. The owner/operator shall ensure that the throughput of molten sulfur at S301, S302, and S303 combined does not exceed 98,915 long tons per consecutive 12-month period. [Cumulative Increase]

2. The owner/operator shall ensure that the throughput of molten sulfur at S465 does not exceed 73,000 long tons per consecutive 12-month period. [Cumulative Increase]

3. The owner/operator shall ensure that S465, Sulfur Pit, is controlled at all times by S1004, Sulfur Recovery Unit. [Cumulative increase, 40 CFR 60.104(b)]

CONDITION 22965
Source S307, U240 Unicracking Unit

1. The owner/operator shall ensure that the throughput of S307 does not exceed 65,000 barrels/day. [Cumulative Increase]

2. The owner/operator shall keep throughput records for this source on a daily basis. The records shall be kept on site for a period of at least 5 years and shall be made available for inspection by District staff upon request. [Cumulative Increase]

3. All pressure relief devices on the process unit shall be vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98% by weight. [8-28-302, BACT]

CONDITION 22966
Source S308, U244 Reforming Unit

1. The owner/operator shall ensure that the throughput of S308 does not exceed 18,500 barrels/day.

2. The owner/operator shall keep throughput records for this source on a daily basis. The records shall be kept on site for a period of at least 5 years and shall be made available for inspection by District staff upon request. [Cumulative Increase]

3. All pressure relief devices on the process unit shall be vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98% by weight. [8-28-302, BACT]

After public comment and at the request of the applicant, the frequency of the recordkeeping requirement in part 2 below was increased to daily.

CONDITION 22967
Source S309, U248 Unisar Unit

1. The owner/operator shall ensure that the throughput of S309 does not exceed 16,740 barrels/day.

2. The owner/operator shall keep throughput records for this source on a daily basis. The records shall be kept on site for a period of at least 5 years and shall be made available for inspection by District staff upon request. [Cumulative Increase]

CONDITION 22968
Source S339, U80 Gasoline/Mid Barrel Blending

1. The owner/operator shall ensure that the throughput of S339 does not exceed 52,600,000 barrels over any rolling 12-month period.

2. The owner/operator shall keep throughput records for this source on a daily basis. The records shall be kept on site for a period of at least 5 years and shall be made available for inspection by District staff upon request. [Cumulative Increase]

CONDITION 22969

Source S434, U246 High Pressure Reactor Train (Cracking)

1. The owner/operator shall ensure that the throughput of S434 does not exceed 8,395,000 barrels over any rolling 12-month period.

2. The owner/operator shall keep throughput records for this source on a monthly basis. The records shall be kept on site for a period of at least 5 years and shall be made available for inspection by District staff upon request. [Cumulative Increase]

3. All pressure relief devices on the process unit shall be vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98% by weight. [8-28-302, BACT]

Condition 22970, Part A, has been imposed to ensure that the emissions increase allowed by Application 13424 is no more than the increase for which the facility has applied. The tanks are not included in the conditions because their applicable requirements will adequately limit the emissions. The following process units are not included because they are existing units and any startup, shutdown, upset, maintenance, or malfunction emissions are considered to be included in their current permits: S307, S308, S318, S432. The fugitive emissions from components are considered to be constant and are not included. S434 and S1004 are new and are included. Condition 1440 places sufficient limits on S1007 and so it is not included. Part A states the allowable emissions limits and includes sufficient monitoring and calculations to ensure that the limits are not exceeded.

Also, the calculated emissions for locomotives were not included.

After the public comment period, the following changes were made:

- Part A.4 was reorganized for clarity.
- The offset reporting requirement in Part B was amended to include banked credits.
- The sources of the contemporaneous offsets were added.
- The NOx limit in part A.2.a was lowered from 14.4 tpy to 13.5 tpy.
- The SO2 limit in part A.2.b was lowered from 2.7 tpy to 2.5 tpy.
- The PM10 limit in part A.2.c was lowered from 2.7 tpy to 2.5 tpy.
- The CO limit in part A.2.e was lowered from 45.72 tpy to 40.72 tpy.
- The ammonia limit in part A.2.g was raised from 5.5 tpy to 6.35 tpy.
- An annual PM10 limit for sources in Facilities A0016 and B7419 was added to ensure that the CFEP project does not exceed PSD thresholds for PM10.

CONDITION 22970

A. CFEP Project Mass Emission Limits

1. Following are the sources that are subject to Condition 22970, part A:
   S45, Heater (U246)
   S434, U246 High Pressure Reactor Train (Cracking)
   S1004, U235 Sulfur Recovery Unit

2. The owner/operator shall ensure that the annual emissions of the above sources do not exceed the following annual emission limits, including startup, shutdown, malfunction, and upset emissions.

a.	NOx	13.5 tpy
b.	SO2	34.4 tpy
c.	PM10	2.5 tpy
d.	POC	1.9 tpy
e.	CO	40.72 tpy
f.	Sulfuric acid mist	6.01 tpy
g.	Ammonia	6.35 TPY

3. The owner/operator shall ensure that the daily emissions of the CFEP do not exceed the following daily emission limit, including startup, shutdown, malfunction, and upset emissions.

a.	Sulfuric acid mist	38 lb/day [PSD]

4. The owner/operator shall determine whether the emissions are below the allowable emissions in Part A.2, as shown below. The owner/operator shall calculate and report the emissions of NOX, SO2, PM10, POC, CO, and sulfuric acid mist on an annual basis in the following manner.
   a. For Source S45
      v. Use the mass emissions data generated by the NOx CEM at S45.
      vi. Use the emissions rates determined by semi-annual source tests for CO at S45.
      vii. Use the emissions rates determined by initial source test for POC, PM10, ammonia, and sulfuric acid mist at S45.
      viii. Use the sulfur analysis of fuel required by Condition 22862, part 11 at S45.
   b. For Source S1004
      iv. Use the mass emissions data generated by the SO2 and CO CEMs at S1004.
      v. Use the emissions rates determined by annual source tests for NOx, sulfuric acid mist, and ammonia, at S1004.
   c. For the refinery flare S296
      iv. Calculate any emissions caused by venting the contents of any part of the sulfur recovery unit including S1004, A48, and A424 to the refinery flare.
      v. Calculate any emissions caused by venting the contents of any part of S434, to the refinery flare.
      vi. The owner/operator shall calculate any emissions caused by venting the feed to Facility B7419, sources S1 or S2 to the refinery flare.

5. If the annual emissions, as determined in part 3, are above the allowable emissions in part A.1, the owner/operator shall supply additional offsets, where applicable, and perform additional analysis for PSD, if necessary***.*** The results of the analysis shall be submitted to the Director of Compliance and Enforcement on an annual basis on the anniversary of the startup of S1004 or S434, whichever is earlier.

6. The annual emissions of the following sources shall not exceed 16.3 tons PM10/yr: S45, S434, and S1004 at Facility A0016, and S2 and S3 at Facility B7419. If the emissions exceed 16.3 tons in any consecutive 12-month period, the owners/operators of Facilities A0016 and B7419 shall provide contemporaneous offsets of PM10 that comply with BAAQMD Regulations 2-2-201 and 2-2-605. [1-104, 2-2-304]

B. Contemporaneous Offset Conditions

1. The owner/operator shall submit an offset report to the Director of Compliance and Enforcement and the Manager of Permit Evaluation at the end of every quarter after the initial date of startup of any of the new CFEP sources below. The report shall contain the detail of banked and contemporaneous offsets provided for each source to show compliance with the provision in BAAQMD Regulation 2-2-410 that offsets must commence no later than the initial operation of a new source or within 90 days after initial operation of a modified source. After all of the offsets required are provided, the owner/operator may submit the final report, even if all of the sources in the CFEP project are not built.

 <u>New CFEP Sources</u>
 Plant B7419, S1, Hydrogen Plant
 Plant B7419, S2, Hydrogen Plant Furnace
 Plant B7419, S3, Hydrogen Plant Flare
 Plant A0016, S45, Heater
 Plant A0016, S434, U246 High Pressure Reactor Train
 Plant A0016, S1004, U235 Sulfur Recovery Unit

 <u>Contemporaneous Offset Sources</u>
 Plant A0016, S1007, Dissolved Air Flotation Unit (DAF)
 Plant A0016, S8, Unit 240 B-1
 Plant A0016, S352 – S357, Steam Power Plant Gas Turbines and HRSGs
 Plant A0022, S2, Kiln K-2
 [2-1-403, 2-2-410]

The facility has agreed to lower the annual SO2 emission limit in part 11a to 29.7 tons per year. Compliance will be determined with the SO2 CEM.

CONDITION 23125

Source S1004, U235 Sulfur Recovery Unit, S503, Sulfur Storage Tank, S504, Sulfur Degassing Unit, S505, Sulfur Truck Loading Rack

For the purposes of this condition, total reduced sulfur shall mean dimethyl disulfide, dimethyl sulfide, hydrogen sulfide, and methyl mercaptan; and reduced sulfur compounds shall mean hydrogen sulfide, carbonyl sulfide, and carbon disulfide.

1. The owner/operator shall ensure that the throughput of molten sulfur at S1004 does not exceed 200 long tons/day. [Cumulative Increase]

2. The owner/operator shall ensure that the throughput of molten sulfur at S503 does not exceed 471 long tons/day. [Cumulative Increase]

3. The owner/operator shall ensure that S1004 is abated at all times of operation by A48, SRU Tail Gas Treatment Unit, and A424, Incinerator. [Cumulative Increase]

4. The owner/operator shall ensure that S503, Sulfur Storage Tank, S504, Sulfur Degassing Unit, and S505, Sulfur Truck Loading Rack, are controlled at all times of operation by the Claus reaction furnace at S1004 or S1003, Sulfur Recovery Units. [Cumulative Increase, 2-1-305]

5. All pressure relief devices on S1004 shall be vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. [8-28-302, BACT]

6. The owner/operator shall ensure that the supplemental fuel used at A424, Tail Gas Incinerator, is PUC quality natural gas. [BACT]

7. The owner/operator shall not exceed the following emission concentrations from S1004/A48/A424:
   a. SO_2 50 ppmv @ 0% O_2, 24-hour basis. [BACT]
   b. CO 75 ppmvd @ 7% O_2, 1-hour basis. [BACT]
   c. NO_x 42.2 ppmv @ 7% O_2, 1-hour basis. [BACT]

8. The owner/operator shall not exceed the following emission concentrations from S1004/A48/A424:
   a. NH_3 12.5 ppmv @ 7% O_2, 24-hour basis [Regulation 2, Rule 5]
   b. H_2S: 2.5 ppmv @ 0% O_2 [Regulation 2, Rule 5]

9. The owner/operator shall not exceed the following hourly limits from S1004/A48/A424:
   a. NO_x: 8.0 lb/hr [2-1-305]
   b. H_2S: 0.23 lb/hr [Regulation 2, Rule 5]
   c. NH_3: 0.88 lb/hr [Regulation 2, Rule 5]

10. The owner/operator shall ensure that daily emissions, including startups, shutdowns, upsets, and malfunctions, from S1004/A48/A424 do not exceed the following limits:
    a. Sulfuric acid mist: 31 lb/day [PSD]
    b. PM10: 3.36 lb/day [2-1-301]

11. The owner/operator shall ensure that that annual emissions, including startups, shutdowns, upsets, and malfunctions, from S1004/A48/A424, do not exceed the following limits per any consecutive 12-month period:
    a. SO_2: 29.7 tons [BACT, Cumulative Increase]

b. NH3: 3.85 tons [Regulation 2, Rule 5]
c. CO: 37.9 tons [BACT, Cumulative Increase]
d. NOx: 11.2 tons [BACT, Cumulative Increase]
e. POC: 0.43 tons [Cumulative Increase]
f. PM10: 0.59 tons [Cumulative Increase]
g. Sulfuric acid mist: 5.65 tons [2-1-301]
h. H2S: 0.975 tons [Regulation 2, Rule 5]
i. Total Reduced Sulfur: 10 tons [PSD]
j. Reduced Sulfur Compounds 10 tons [PSD]

12. Prior to the commencement of construction, the owner/operator shall submit plans to the District's Source Test Division to obtain approval of the design and location of the source test ports. The sample ports shall be installed in accordance with Manual of Procedures, Volume 4, Section 1.2.4. Ports for particulate testing shall be installed. [basis: Regulation 1-501]

13. No later than 90 days from the startup of S1004, the owner/operator shall conduct District-approved source tests to determine (1) initial compliance with the limits in Parts 7, 8, 9, and 13 for NOx, CO, POC, PM10, SO2, sulfuric acid mist, H2S, ammonia, (2) the BAAQMD Regulation 6 requirements below, and (3) the emission rates in lbs/dry standard cubic foot of NOx, POC, PM10, sulfuric acid mist, NH3, H2S, and reduced sulfur compounds. The owner/operator shall conduct the source tests in accordance with Part 19. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test. During the source test, the owner/operator shall determine the temperature required to achieve an outlet concentration of 2.5 ppmv H2S @ 0% O2, while meeting all other limits. The temperature shall become an enforceable limit.
    a. BAAQMD Regulation 6-310: 0.15 gr PM/dscf
    b. BAAQMD Regulation 6-311: PM emissions based on Process Rate Weight
    c. BAAQMD Regulation 6-330: SO3 and H2SO4 limit

    If the rate of reduced sulfur compounds, including H2S, exceeds 2.2 lb/hr, or if the rate of total reduced sulfur, including H2S, exceeds 2.2 lb/hr, the District reserves the right to require additional PSD analysis or to impose a higher temperature limit for S424, Incinerator, to control total reduced sulfur and reduced sulfur compounds.
    [BACT, Cumulative Increase; Regulation 2, Rule 5; BAAQMD Regulation 6; PSD]

14. After the initial source test required in part 13 of this condition, the owner/operator shall ensure that the minimum temperature shall not be lower than the temperature determined in the initial source test. The temperature limit will be added to this part after the source test is performed. The owner/operator shall submit the source test results to District staff no later than 60 days after any source test. [Offsets]

15. To determine compliance with the temperature limit in part 14, A48, Thermal Oxidizer, shall be equipped with a temperature measuring device capable of continuously measuring and recording the temperature in A48. The

owner/operator shall install, and maintain in accordance with manufacturer's recommendations, a temperature measuring device that meets the following criteria: the minimum and maximum measurable temperatures with the device are (TBD) degrees F and (TBD) degrees F, respectively, and the minimum accuracy of the device over this temperature range shall be 1.0 percent of full-scale. [Regulation 1-521]

16. The temperature limit in part 14 shall not apply during an "Allowable Temperature Excursion", provided that the temperature controller setpoint complies with the temperature limit. For the purposes of parts 16 and 17 of this condition, a temperature excursion refers only to temperatures below the limit. An Allowable Temperature Excursion is one of the following:

a. A temperature excursion not exceeding 20 degrees F; or

b. A temperature excursion for a period or periods which when combined are less than or equal to 15 minutes in any hour; or

c. A temperature excursion for a period or periods which when combined are more than 15 minutes in any hour, provided that all three of the following criteria are met.

i. the excursion does not exceed 50 degrees F;

ii. the duration of the excursion does not exceed 24 hours; and

iii. the total number of such excursions does not exceed 12 per calendar year (or any consecutive 12 month period).

Two or more excursions greater than 15 minutes in duration occurring during the same 24-hour period shall be counted as one excursion toward the 12 excursion limit. [Regulation 2-1-403]

17. For each Allowable Temperature Excursion that exceeds 20 degrees F and 15 minutes in duration, the Permit Holder shall keep sufficient records to demonstrate that they meet the qualifying criteria described above. Records shall be retained for a minimum of five years from the date of entry, and shall be made available to the District upon request. Records shall include at least the following information:

a. Temperature controller setpoint;

b. Starting date and time, and duration of each Allowable Temperature Excursion;

c. Measured temperature during each Allowable Temperature Excursion;

d. Number of Allowable Temperature Excursions per month, and total number for the current calendar year; and

e. All strip charts or other temperature records.

[Regulation 2-1-403]

18. For the purposes of parts 16 and 17 of this condition, a temperature excursion refers only to temperatures below the limit. (Basis: Regulation 2-1-403)

19. The owner/operator shall submit protocols for all source test procedures to the District's Source Test Section at least three weeks 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 projected test dates at least 7 days prior to testing.
[BACT, Cumulative Increase; Regulation 2, Rule 5]

20. The owner/operator shall perform an annual District-approved source test to verify compliance with the following requirements. A copy of the source test results shall be provided to the District Director of Compliance and Enforcement within 60 days of the test.
    a. BAAQMD Regulation 6-310: 0.15 gr PM/dscf
    b. BAAQMD Regulation 6-311: PM emissions based on Process Rate Weight
    c. BAAQMD Regulation 6-330: SO_3 and H_2SO_4 limit
    d. Emission rates in parts 7c, 8a, 8b, 9a, 9b, and 9c of this condition.
    e. Emission rates of sulfuric acid mist, total reduced sulfur, and reduced sulfur compounds

    [BACT, Regulation 6, PSD; Regulation 2, Rule 5; Cumulative increase]

21. The owner/operator shall install, calibrate, maintain, and operate a District-approved continuous emission monitor and recorder for exhaust gas flowrate, SO_2 and O_2. The owner/operator shall keep exhaust gas flow, SO_2 and O_2 data for at least five years and shall make these records available to the District upon request. The owner/operator shall measure SO_2 concentration and mass emissions on a clock-hour basis. The monitors shall comply the requirements of 40 CFR 60.105, 40 CFR 63.1572, and the District's Manual of Procedures, Volume 5. [BACT, Cumulative Increase, 40 CFR 63.1568(a)(1)(i)]

22. The owner/operator shall install, calibrate, maintain, and operate a District-approved continuous emission monitor and recorder for exhaust gas flow and CO. The owner/operator shall keep flow and CO data for at least five years and shall make these records available to the District upon request. The owner/operator shall measure CO concentration and mass emissions on a clock-hour basis. The monitors shall comply the requirements of the District's Manual of Procedures, Volume 5. [BACT, Cumulative Increase]

23. The owner/operator will ensure that S1004, SRU, complies with all applicable provisions of 40 CFR 60, Subpart J, and 40 CFR 63, Subpart UUU. This provision will be deleted when the applicable citations from these standards are incorporated into the Major Facility Review permit. [40 CFR 60, Subpart J; 40 CFR 63, Subpart UUU]

24. The owner/operator shall keep throughput records for sources S1004 and S503 on a daily basis. The records shall be kept on site for a period of at least 5 years and shall be made available for inspection by District staff upon request. [Cumulative Increase]

25. The owner/operator shall use the source tests required in parts 13 and 20 to determine compliance with the daily limit in part 10 and the annual limits in parts 11b, 11d, 11e, 11f, 11h, and 11i. At the end of every month, the owner/operator shall summarize the exhaust gas flow in dry standard cubic feet for the month and shall calculate the estimated emissions of each pollutant for the previous consecutive 12-month period and for H2S for each day of the month using the emission rate determined in the last source test. The summaries and calculations shall be completed within 60 days of the end of each month. Alternately, the owner/operator may establish a daily and monthly exhaust gas flow level after each source test that will ensure compliance with the daily and annual limits. In this case, the owner/operator will log the daily and monthly exhaust gas flows from S1004/A48/A424. [Cumulative increase; Regulation 2, Rule 5; Cumulative Increase, PSD]

26. The Owner/Operator shall perform a visible emissions check on Source S1004 on a monthly basis. The visible emissions check shall take place while the equipment is operating and during daylight hours. If any visible emissions are detected, the owner/operator shall have a CARB-certified smoke reader determine compliance with the opacity standard, using EPA Method 9 or the procedures outlined in the CARB manual, "Visible Emissions Evaluation" for six (6) minutes within three (3) days and record the results of the reading. If the reading is in compliance with the Ringelmann 1.0 limit in BAAQMD Regulation 6-301, the reading shall be recorded and the owner/operator shall continue to perform a visible emissions check on a monthly basis. If the reading is not in compliance with the Ringelmann 1.0 limit in BAAQMD Regulation 6-301, the owner/operator shall take corrective action and report the violation in accordance with Standard Condition 1.F of the Title V permit. The certified smoke-reader shall continue to conduct the Method 9 or CARB Visible Emission Evaluation on a daily basis until the daily reading shows compliance with the applicable limit or until the equipment is shut down. Records of visible emissions checks and opacity readings made by a CARB-certified smoke reader shall be kept for a period of at least 5 years from date of entry and shall be made available to District staff upon request. [Basis: Regulations 6-301, 2-1-403]

Members of the public commented on odors originating at the ConocoPhillips refinery. In response to those comments, the CEQA documents state that a fourth odor abatement compressor will be installed. To ensure that A7, Odor Abatement System, is properly operated, and that the new compressor is installed, the District has imposed the following permit condition. The condition requires pressure monitoring at the tanks that are controlled by the odor abatement system so that the tanks operate below the set pressure of the pressure/vacuum valves that can relieve to atmosphere.

CONDITION 23724
For Sources S135 (Tank 200), S137 (Tank 202), S139 (Tank 204), S140 (Tank 205), S158 (Tank 258), S168 (Tank 269), S173 (Tank 280), S174 (Tank 281), S175 (Tank 284), S182 (Tank 294), S360 (Tank 223), S445 (Tank 271), S449 (Tank 285), Tank 235, and Tank 236.

1a. The owner/operator shall ensure that all sources subject to this permit condition are abated by A7, Vapor Recovery System except for S168, S173, S174, which shall be abated prior to startup of S434. [Basis: Regulation 2-1-403]

1b. The owner/operator shall ensure that a fourth compressor is added to A7, Odor Abatement System, before the following sources are controlled by A7: S168, S173, S174. [Basis: Regulation 2-1-301, 2-1-305, 2-1-403, CEQA]

1c. The new odor abatement compressor, or a dedicated compressor, shall be designed and installed to supplement G-503, Flare Gas Recovery Compressor. [CEQA]

~~2. The owner/operator shall ensure that all tanks subject to this permit condition are blanketed by utility-grade natural gas. [Basis: Regulation 2-1-403]~~

~~3. Within 21 months of issuance of the Authority to Construct, the owner/operator shall equip all tanks subject to this permit condition with District-approved pressure monitoring devices. Within 3 months of issuance of the Authority to Construct, the owner/operator shall equip the following tanks with District-approved pressure monitoring devices: S139, S140, S182, S360, S445, and S449. [Basis: Regulation 2-1-403]~~

~~4. After the pressure monitoring devices are installed, the owner/operator shall ensure that tanks listed below operate at all times below their respective minimum set pressures, as shown in 4a and 4b of this condition. Any recorded pressure in excess of the minimum pressure shall be reported to the District's Enforcement and Engineering Divisions within 10 days of the pressure excess. The owner/operator must conduct an investigation of the incident to determine if the pressure excess resulted in the pressure/vacuum (PV) valve lifting to atmosphere and if so, why there was a pressure excess that resulted in the PV valve lifting to atmosphere.~~

~~Results of the investigation must be reported to the District's Enforcement and Engineering Division within 30 days of the initial report. Any recorded pressure in excess of the minimum set pressure shall be considered an indication of a valve lift to atmosphere unless a District approved tell-tale indicator on the PV valve shows that the valve did not lift, or the owner/operator demonstrates to the satisfaction of the APCO that the recorded pressure excess was the result of a monitoring, recording or other malfunction.~~

~~The minimum set pressure for each storage tank must be submitted in a report to the District's Enforcement and Engineering Divisions within 21 months of issuance of the Authority to Construct and within 3 months of issuance of the Authority to Construct for the following tanks: S139, S140, S182, S360, S445, S449.~~

~~a.~~

~~Source Number~~	~~Minimum Set Pressure (inches H2O)~~
135	TBD
137	TBD
139	TBD
140	TBD
168	TBD
182	TBD
360	TBD
445	TBD
449	TBD

The owner/operator shall submit an accelerated permit application to include any change to any of the pressures above. Any amendment to the Title V permit to include the pressures above shall be submitted as a minor revision to the Title V permit.
[Basis: Regulation 8, Rule 5]

b.

Source Number	Minimum Set Pressure (inches H2O)
158	TBD
173	TBD
174	TBD
175	TBD
Tank 235	TBD
Tank 236	TBD

The owner/operator shall submit an accelerated permit application to include any change to any of the pressures above. Any amendment to the Title V permit to include the pressures above shall be submitted as a minor revision to the Title V permit.
[Basis: Regulation 2-1-403]

~~5. The owner/operator shall ensure that each pressure relief valve for each tank must be set at or above its nominal set pressure listed in Part 4 of this permit condition. [Basis: Regulation 2-1-403]~~

6. Corrective Plan

The corrective plan is a means for ConocoPhillips to correct occasional exceedances, to stay within the working pressure limits and thus to remain in compliance with District Regulations. If a PV valve has been determined to have lifted three times in a 12 month period, ConocoPhillips shall implement abatement measures to prevent the recurrence of the type of incident which caused the valve to lift. This plan is intended to provide a mechanism for bringing ConocoPhillips back into compliance should a temporary exceedance occur. This plan does not constitute an alternative means of compliance. [Basis: Regulation 2-1-403]

a. If, during any consecutive 12-month period, more than three instances of a PV valve release to atmosphere attributed to a storage tank subject to this permit condition are reported, ConocoPhillips shall propose a method to correct the exceedance and to ensure compliance with District regulations and permit conditions. The proposed method is subject to approval by the Air Pollution Control Officer. Potential methods include but are not limited to increasing the nominal set pressure of the pressure/vacuum valve, bladder tank(s) for additional short-term vapor storage capacity, dedicated vapor recovery flare, pilot control on pressure relief valves, flow meters on vapor recovery tanks to monitor blanket gas flows, replacement of tanks, and naphtha degassers. [Basis: Regulation 2-1-403]

7. To determine compliance with the above conditions, the owner/operator shall maintain the following records and provide all of the data necessary to evaluate compliance with the above parts, including, but not necessarily limited to the following information:

a. Pressure measurements from tanks listed in part 4 of this condition. Pressure shall be recorded at least for one-minute interval for each tank.

All records shall be retained on site for five years, from the date of entry and made available for inspection by the District staff upon request. These recordkeeping requirements shall not replace the recordkeeping requirements contained in any applicable District regulation. [Basis: Regulation 2-1-403]

8. The requirement to report pressures in excess of the minimum pressure as described in part 4 of this permit condition, shall start after 21 months of issuance of the Authority to Construct and 3 months after issuance of the Authority to Construct for the following tanks: S139, S140, S182, S360, S445, S449. [Basis: 2-1-403]

9. The permit to operate is contingent upon compliance with Regulation 1-301, Standard for Public Nuisance, and Regulation 7, Odorous Substances. Upon receipt of a violation for either of these regulations, the Air Pollution Control Officer may require the owner/operator to install additional emission control measures as stated in Part 6 of this permit condition. [Basis: Regulations 1-301, 7-301, 7-302]

Condition 23725 replaces Condition 21099 for fugitive components because the BACT determination has been updated. The leak standard is explicit in addition to the required technology. A requirement for leak detection for pumps in heavy liquid service has been added. An annual limit of 6.1 tons per year of POC, which is equivalent to the calculated emissions assuming a leak rate of 100 ppm, has been added. This annual rate is 0.2 tons per year less than rate that was in the final application.

The facility estimates that there will be up to 100 valves in high pressure high temperature gaseous service that will not be any of the types listed in part 1a of the condition because the valves are not available for this service. The District expects the facility to demonstrate that the leak rates of the valves that are installed are equivalent to the valves specified before installation. A manufacturers guarantee may be used to demonstrate equivalency.

CONDITION 23725

~~CONDITIONS FOR CLEAN FUELS EXPANSION PROJECT (CFEP) FUGITIVE COMPONENTS~~

1. Fugitive Equipment

   a. The owner/operator shall as part of the CFEP install only the following types of valves in light hydrocarbon service where the hydrocarbon has an initial boiling point less than or equal to 302 degree F: (1) bellows sealed, (2) live loaded, (3) graphite packed, (4) quarter-turn (e.g., ball valves or plug valves), or equivalent as determined by the APCO. [Basis: BACT]

   b. The owner/operator shall comply with a leak standard of 100 ppm of TOC (measured as C1) at any valve installed as part of the CFEP in hydrocarbon service. The owner/operator shall not be considered in violation of the leak standard if the owner/operator complies with the applicable minimization and repair provisions contained in Regulation 8, Rule 18. Valves that are not of a type listed in part 1 (a) and for which a leak greater than 100 ppm (measured as C1) has been determined, shall become subject to the inspection provisions contained in Regulation 8-18. If the leak remains greater than 100 ppm (measured as C1) after repair, or if the valve is determined to have a leak greater than 100 ppm (measured as C1) a second time within a 5-year period, the owner/operator shall replace the valve with a type listed in part 1 (a) within 5 years or at the next scheduled turnaround, whichever is sooner. [Basis: BACT, Regulation 8, Rule 18]

   c. The owner/operator shall install graphitic-based gaskets on all flanges or connectors (gasketed) installed as part of the CFEP in light hydrocarbon service unless the owner/operator demonstrates to the satisfaction of the APCO that the service requirements prevent this gasket material from being used. [Basis: BACT]

d. The owner/operator shall install double mechanical seals with barrier fluid; or gas seal system vented to a thermal oxidizer or other District approved equivalent control device or technology as determined by the APCO on all compressors installed as part of the CFEP. [Basis: BACT]

e. The owner/operator shall comply with a leak standard of 100 ppm of TOC (measured as C1) at any pumps and/or compressors installed as part of the CFEP in hydrocarbon service. The owner/operator shall not be considered in violation of the leak standard if the owner/operator complies with the applicable minimization and repair provisions contained in Regulation 8-18. All pumps and/or compressors subject to the leak standard of 100 ppm TOC shall be included in the total number of pumps and compressors used in Regulation 8-18-306.2 to determine the total number of non-repairable pumps and compressors allowed. [Basis: BACT]

f. The owner/operator shall install double mechanical seals with barrier fluid; dual nitrogen gas purge seals; magnetically coupled pumps; canned pumps; magnetic fluid sealing technology; gas seal system vented to thermal oxidizer, or other BAAQMD approved equivalent control device; or District approved control technology as determined by the APCO on all pumps installed as part of the CFEP in light hydrocarbon service where the hydrocarbon has an initial boiling point less than or equal to 302 degree F. The owner/operator shall install double mechanical seals or District approved equivalent technology on all pumps in heavy hydrocarbon service where the hydrocarbon has an initial boiling point greater than 302 degree F and flash point less than 250 degree F. [Basis: BACT]

g. Unless the equipment exclusively handles material(s) with a flash point greater than or equal to 250 degree F, the owner/operator shall identify all new pumps and compressors installed as part of the CFEP in hydrocarbon service with a unique permanent identification code and shall include all new and replaced fugitive equipment in the Regulation 8, Rule 18 fugitive equipment monitoring and repair program. The owner/operator shall monitor all repaired equipment within 24 hours of the repair. [Basis: Cumulative Increase, BACT]

2. The Owner/Operator shall submit a count of installed pumps, compressors, valves, pressure relief devices, and flanges/connectors every 180 days after startup of the first unit until completion of the CFEP project. The owner/operator has been permitted to install the following number of fugitive components for the Clean Fuels Expansion Project:

Pumps: 16 [As identified in part 1 (g)]
Compressors: 3
Valves: 1,730

Connectors (No Flanges): 1,961
Flanges: 3,450
Pressure Relief Devices: 118 non-atmospheric

~~The owner/operator shall not exceed 6.1 tons per year of POC emissions measured as C1 from the total fugitive component count installed in TOC services as part of the CFEP. Compliance with this provision shall be verified quarterly using methods described in Part 3. The results shall be submitted to the District on a quarterly basis for two years commencing with start-up. Documentation of results shall be kept on site for five years.~~

~~If there is an increase in the total fugitive component counts, the plant's cumulative emissions for the project shall be adjusted, subject to APCO approval, to reflect the difference between emissions based on predicted component counts versus actual component counts. The owner/operator may have enough remaining contemporaneous emissions reduction credits (ERCs) to cover any increase in POC fugitive emissions beyond the original projection. If not, the owner/operator shall provide to the District all additional required offsets at an offset ratio of 1.15:1 no later than 21 days after the submittal of the final POC fugitive equipment count. If the actual component count is less than the predicted count, at the completion of the project, the total will be adjusted accordingly. Any ERCs applied by the facility in excess of the actual total fugitive emissions estimate based on actual counts as opposed to estimated will be credited back to the owner/operator. [Basis: Cumulative Increase, Offsets, Regulation 2, Rule 5]~~

3. ~~The owner/operator shall calculate fugitive emissions from CFEP fugitive components utilizing District approved methods. [Basis: Cumulative Increase, BACT, Offsets]~~

4. ~~Inspections~~

    a. ~~The owner/operator shall conduct inspections of CFEP fugitive components in light hydrocarbon service with an initial boiling point less than or equal to 302 degree F in accordance with the frequency listed below:~~

~~Pumps: Quarterly~~

~~Compressors: Quarterly~~

~~Valves: Quarterly~~

~~Connectors (Not Flanges): Annual~~

~~Flanges: Annual~~

~~[Basis: BACT, Regulation 8, Rule 18]~~

~~b. The owner/operator shall conduct quarterly inspections of all CFEP pumps in hydrocarbon service with a flash point less than 250 degree F. [Basis: BACT]~~

By: ______________________________________ October 5, 2007
Brenda Cabral Date
Supervising Air Quality Engineer

APPENDIX A

Emission Calculations

S45, Heater (U246), 85 MMbtu/hr

ConocoPhillips proposed the following BACT levels for the new heater:

Pollutant	BACT	Emission Factors (lb/MMbtu)
NOx	7 ppmvd @3% O2	0.0086
CO	28 ppmvd @3% O2	0.0210
SO2	Use of natural gas and/or RFG; 100 ppmv total sulfur in RFG	0.0126
POC	Use of natural gas and/or RFG 5.5 lb/MMcf	0.0041
PM10	Use of natural gas and/or RFG 7.6 lb/MMcf	0.0057

Hourly mass emission rates for the process heater were determined by multiplying the “pounds per MMBtu” emission factor by the rated maximum heat input of the heater.

Daily and annual mass emissions were calculated based on 24-hour-per-day and 365-day per-year operation, respectively. Daily and annual process heater emission rates for the new Heater, S45, were shown below.

	lb/hr	lb/day	ton/yr
NOx	0.73	18	3.2
SO_2	1.07	26	4.7
PM10	0.48	12	2.1
POC	0.35	8.4	1.5
CO	1.79	43	7.8

After public notice, the District determined that lower concentrations of NOx and CO were achieved in practice by heaters burning refinery fuel in the SCAQMD. The lower levels were 5 ppmv NOx @ 3% O2, dry, and 10 ppmv CO @ 3% O2, dry. As explained in Section 3 of this evaluation, the heater will operate at low levels for much of the time, where the 10 ppm CO limit is not achievable. The facility has proposed, and the District has concurred with, a limit of 28 ppm CO below 30 MMbtu/hr. Therefore, the hourly mass emission rate for CO will remain approximately the same at high and low levels of operation. The lower NOx limit is achievable at high and low levels of operation.

Following are the amended emission factors:

Pollutant	BACT	Emission Factors (lb/MMbtu)
NOx	5 ppmvd @3% O2	0.0061
CO	10 ppmvd @3% O2	0.0075
SO2	Use of natural gas and/or RFG; 100 ppmv total sulfur in RFG	0.0126
POC	Use of natural gas and/or RFG 5.5 lb/MMcf	0.0041
PM10	Use of natural gas and/or RFG 7.6 lb/MMcf	0.0057

Following are the amended hourly, daily, and annual mass emission rates:

	lb/hr	lb/day	ton/yr
NOx	0.52	12.4	2.3
SO_2	1.07	26	4.7
PM10	0.48	12	2.1
POC	0.35	8.4	1.5
CO	0.64	15.3	2.8

The estimated emissions of toxic air contaminants are shown below. Emission factors from WSPA/API's Air Toxic Emission Factors for Combustion Sources Using Petroleum-Based Fuels, final report, Volume 2, Appendix B, April 14, 1998 have been used for the calculations, except that the ammonia emission rate is based on the 15 ppmv limit.

Pollutant	Emissions lb/yr	Emissions lb/hr
Acenaphthene	1.76E-03	2.01E-07
Acenaphthylene	1.15E-03	1.32E-07
Acetaldehyde	1.14E+01	4.75E-01
Ammonia	5,96+03	5.79-01
Antimony	3.85E-01	4.39E-05
Arsenic	6.33E-01	7.23E-05
Benzene	4.82E+01	5.50E-03
Benzo(a)anthracene	2.39E-02	2.73E-06
Benzo(a)pyrene	6.67E-02	7.62E-06
Benzo(b)fluoranthene	3.01E-02	3.43E-06
Benzo(k)fluoranthene	1.79E-02	2.05E-06
Cadmium	7.36E-01	8.40E-05
Chromium (Total)	7.97E-01	9.10E-05
Chrysene	1.21E-03	1.39E-07
Copper	3.13E+00	3.58E-04

Pollutant	Emissions lb/yr	Emissions lb/hr
Ethylbenzene	2.25E+01	2.57E-03
Fluoranthene	2.28E-03	2.60E-07
Fluorene	8.04E-03	9.18E-07
Formaldehyde	8.27E+01	9.44E-03
Indeno(1,2,3-cd)pyrene	7.67E-02	8.76E-06
Lead	3.64E+00	4.16E-04
Manganese	5.07E+00	5.79E-04
Mercury	1.34E-01	1.53E-05
Naphthalene	2.33E-01	2.66E-05
Nickel	7.01E+00	8.01E-04
Phenanthrene	1.09E-02	1.24E-06
Phenol	4.19E+00	4.79E-04
Propylene	1.62E+00	1.84E-04
Pyrene	1.85E-03	2.11E-07
Selenium	1.46E-02	1.67E-06
Silver	1.20E+00	1.37E-04
Toluene	7.97E+01	9.10E-03
Xylene (Total)	2.78E+01	3.17E-03
Zinc	1.55E+01	1.77E-03

Tanks
S98, S122, S123, S124, S128, Tanks, EFRT
S118, Tank No. 163, fixed roof, 5.3k barrels
S139, S140, and S182, Fixed Roof Tanks, abated by A7, Vapor recovery System

Tanks S139, S140, and S182 are abated by vapor recovery and will not have an increase in emissions.

The emissions from S98, S123, and S124, which will have a change in service, are shown below.

Emission Increase from S98, S123, and S124

Tank Emissions						
Tank Number	**S98**		**S123**		**S124**	
Material	**Gasoline**		**Gasoline (MUK)**		**Gasoline (LUK)**	
Throughput (bbl)	7,446,000		3,000,000		3,000,000	
Total POC Emissions (lb/yr)	12,373		993		2,826	
Toxic Emission	**(lb/hr)**	**(lb/yr)**	**(lb/hr)**	**(lb/yr)**	**(lb/hr)**	**(lb/yr)**
Benzene	4.58E-03	40.08	3.17E-04	2.78	2.28E-03	20
Cyclohexane	6.73E-03	58.96	4.37E-04	3.83	1.04E-03	9.1
Ethylbenzene	7.63E-04	6.68	5.38E-04	4.71	2.20E-06	0.019
Hexane	2.75E-02	240.47	7.25E-04	6.36	5.28E-03	46
Naphthalene	7.63E-05	0.67	0.00E+00	0.00	2.20E-07	0.0019
Toluene	1.30E-02	113.55	5.16E-03	45.24	1.22E-04	1.1
Xylene (Total)	8.39E-03	73.48	2.78E-03	24.36	7.33E-06	0.064
1,2,4-Trimethylbenzene	1.33E-03	11.69	5.38E-04	4.71	0.00E+00	0

* Baseline period is 2002, 2003 and 2004.
Emissions estimated by ConocoPhillips using EPA AP-42 methodology with option for zero-gap seals

Emission Increase from S98, S123, and S124

Tank Emissions			
Tank Number	**S98**	**S123**	**S124**

Substance	Speciations		
	Gasoline	MUK	LUK, LTWXY
	Vapor Weight Fraction of ROG	Vapor Weight Fraction of ROG	Vapor Weight Fraction of ROG
Benzene	0.0032	0.0028	0.0071
Cyclohexane	0.0048	0.0039	0.0032
Ethylbenzene	0.0005	0.0047	0.0000
Hexane	0.0194	0.0064	0.0164
Naphthalene	0.0001	0.0000	0.0000
Toluene	0.0092	0.0456	0.0004
Xylene (Total)	0.0059	0.0245	0.0000
1,2,4-Trimethylbenzene	0.0009	0.0047	0.0000

Source Number	Tank Number	Annual Proposed Limit (bbl)	Emissions lb/yr Proposed	Baseline	Increase	Emissions lb/hr Increase	Emissions TPY Increase
S118	163	900	6	4	2	2.63E-04	0.00115
S122	167	2,000,000	9,574	2,312	7,262	8.29E-01	3.631
S128	174	5,100,000	3,094	721	2,373	2.71E-01	1.1865
				TOTAL	9,637	1.10E+00	4.81865

Change in Emissions from Existing Tanks

		Emissions lb/yr												
Source Number	Product Stored	Benzene	Cyclo-hexane	Ethyl-benzene	Hexane	Naphtha-lene	Toluene	Xylene (Total)	1,2,4-Trimethyl-benzene	2,4-di-tert-butyl-phenol	Ortho-tert-butyl-phenol	Mixed butylated phenols	Phenol	Toluene
S118	Additive									0.0391	0.1840	0.2760	0.0184	0.4600
S122	Gasoline (LUK)	51.2466	23.3110	0.0495	118.8327	0.0050	2.7356	0.1650	0.0000					
S128	Gasoline	7.6864	11.3087	1.2811	46.1186	0.1281	21.7782	14.0918	2.2419					

		Emissions lb/hr												
Source Number	Product Stored	Benzene	Cyclo-hexane	Ethyl-benzene	Hexane	Naphtha-lene	Toluene	Xylene (Total)	1,2,4-Trimethyl-benzene	2,4-di-tert-butylphenol	Ortho-tert-butylphenol	Mixed butylated phenols	Phenol	Toluene
S118	Gasoline									4.46E-06	2.10E-05	3.15E-05	2.10E-06	5.25E-05
S122	Gasoline (LUK)	5.85E-03	2.66E-03	5.65E-06	1.36E-02	5.65E-07	3.12E-04	1.88E-05	0.00E+00					
S128	Gasoline	8.77E-04	1.29E-03	1.46E-04	5.26E-03	1.46E-05	2.49E-03	1.61E-03	2.56E-04					

The emissions were calculated using EPA's AP-42 methodology.

S1004, U235 Sulfur Recovery Unit (200 long tons/day)
S301-S303, S465, Sulfur Pits
S503, Sulfur Storage Tank
S504, Sulfur Degassing Unit
S505, Sulfur Truck Loading Rack abated by A424, Tail Gas Incinerator

S1004, U235 Sulfur Recovery Unit (200 long tons/day)
Following is the estimate of SO2 emissions based on a flow rate of 77,000 lb/hr through the SRU, which is provided by the SRU designers, and a limit of 50 ppmdv SO2 at 0% O2.

SRU SO2 Emissions

2 H2S + 3 O2 --> 2 SO2 + 2 H2O
Assume sample is mostly air at 1 atm and 298 K (vol is approx. 0.856 m^3/kg)

P=	101000	Pa	
T=	298	K	
R=	8.3	(m^3 * Pa)/(K * mol)	
Ppmvd=	50	mL/m^3	based on Shell Martinez Refinery's Title V Permit Condition 12271 Part 68
density of air=	1.168	kg/m^3	at 1 atm and 298K
Mwsample=	28.36	g/gmol	
MWSO2=	64	g/gmol	
MWN2=	28	g/gmol	
MWO2=	32	g/gmol	
mole fraction of N2 in air =	0.78		
stack flow rate from SRU TGTU stack=	77700	lbs/hour	at 0% O2 and water (also equal to 1.04 mmscfh with MW=28.36)
=	1.24E+06	gmol/hr	
=	1.09E+10	gmol/yr	
stack flow rate from incinerator stack=	1.19E+06	gmol/hr	
=	1.04E+10	gmol/yr	
SO2=	5.95E+01	gmol/hr	
=	5.21E+05	gmol/yr	
=	36.7	TPY	
=	201	lb/day	
=	8.4	lb/hr	

Following is the estimate of the maximum H2S emissions from the SRU assuming a flow of 77,000 lb/hr through the SRU and a concentration of 2.5 ppmvd @ 0% O2.

SRU H2S Emissions

Assume sample is mostly air at 1 atm and 298 K (vol is approx. 0.856 m^3/kg)

P=	101000	Pa	
T=	298	K	
R=	8.3	(m^3 * Pa)/(K * mol)	
Ppmvd=	2.5	mL/m^3	based on Shell Martinez Refinery's Title V Permit Condition 12271 Part 68
density of air=	1.168	kg/m^3	at 1 atm and 298K
Mwsample=	28.36	g/gmol	
MWH2S=	34	g/gmol	
MWN2=	28	g/gmol	
MWO2=	32	g/gmol	
mole fraction of N2 in air =	0.78		
stack flow rate from SRU TGTU stack=	77700	lbs/hour	at 0% O2 and water (also equal to 1.04 mmscfh with MW=28.36)
=	1.24E+06	gmol/hr	
=	1.09E+10	gmol/yr	
stack flow rate from incinerator stack=	1.19E+06	gmol/hr	
=	1.04E+10	gmol/yr	
H2S=	2.97E+00	gmol/hr	
=	2.6E+04	gmol/yr	
=	$\boxed{0.975}$	TPY	
=	5.3	lb/day	
=	0.23	lb/hr	

The NOx, CO, and ammonia (NH3) emissions are calculated in the same manner except that the correction for oxygen is 7%.

SRU Incinerator CO, NOx and NH3 Emission Calculations

SRU Thermal Incinerator stack flow=	77700	lbs/hour	(@ 0% O2 and water)
MWsample=	28.36	g/gmol	

CO emissions at 75 ppm @ 7% O2 [1]

density of air=	379	ft^3/lbmole
CO Conc =	75	ppmvd
MWCO=	28	lb/lbmole
CO emissions=	8.65	lb/hr
CO emissions=	208	lb/day
CO emissions=	37.9	TPY

NOx emissions at 13.5 ppm @ 7% O2 [1]

density of air=	379	ft^3/lbmole
NOx Conc =	13.5	ppmvd
MW NOx=	46	lb/lbmole
NOx emissions=	2.56	lb/hr
NOx emissions=	61	lb/day
NOx emissions=	11.21	TPY

NH3 emissions at 12.5 ppm @ 7% O2

density of air=	379	ft^3/lbmole
NH3 Conc =	12.5	ppmvd (@7% O2)
MWNH3 =	17	lb/lbmole

NH3 emissions=	0.88	lb/hr
NH3 emissions=	21	lb/day
NH3 emissions=	3.83	TPY

The facility has based the emissions of PM10 and POC, for the SRU complex on the heat input of the incinerator as follows:

SRU Incinerator

Pollutant	Emission Factor	EF (lb/MMBtu)	Reference
PM10	7.6 lb/MMcf	0.0075	AP42 Section 1.4, Natural Gas Combustion
POC	5.5 lb/MMcf	0.0054	AP42 Section 1.4, Natural Gas Combustion

(1) Assumed firing rate: 18 MMBtu/hr

1,546,756 Therms/yr

Daily emissions assume 24 hr/day operation.

Annual emissions assume 365 day/yr operation.

Assumptions for emissions factor table above:

(1) NOx and CO "ppm" emission factors converted to "lb/MMBtu" as follows:

(x [lb/MMBtu]) = (y ppm @ 7% O2) * (21% - 0%) / (21% - 7%) * (EPA Fd Factor [ft3/MMBtu]) / (Molar Volume [ft3/lbmol]) * (Molecular weight [lb/lbmol])

PM10 and POC "lb/MMcf" emission factors converted to "lb/MMBtu" as follows:

(x [lb/MMBtu]) = (Emission factor [lb/MMcf]) / (Refinery gas heat content [Btu/scf])

EPA Fd Factor:	8710	ft3/MMBtu - based on EPA Method 19 (40 CFR 60)
Molar volume:	379	ft3/lbmol (at STP: 25 C, 1 atm)
NOx MW:	46	lb/lbmol
CO MW:	28	lb/lbmol
SO2 MW:	64	lb/lbmol

Natural gas: 1020 Btu/scf (AP42)

Based on the emission factors above, the facility has estimated hourly, daily, and annual emissions.

Hourly, Daily and Annual SRU Emissions

	Emissions[1]		
Pollutant	**lb/hr**	**lb/day**	**ton/yr**
PM10	0.14	3.24	0.59
POC	0.10	2.33	0.43

Notes:

(1) Assumed heater rating: 18 MMBtu/hr

Daily emissions assume 24 hr/day operation.

Annual emissions assume 365 day/yr operation.

Based on the representations by the facility, the unit will be limited to the above amounts of SO2, H2S, NH3, NOX, PM10, POC, and CO.

Fugitive Sources
S307, U240 Unicracking Unit
S308, U244 Reforming Unit
S309, U248 UNISAR Unit
S318, U76 Gasoline Blending
S339, U80 Gasoline/Mid Barrel Blending
S432, U215 Deisobutanizer
S434, U246 High Pressure Reactor Train (Cracking)
S1004, U235 Sulfur Recovery Unit (200 long tons/day)

The following emission estimates were provided by ConocoPhillips and the District has found them to be acceptable.

New process equipment associated with the CFEP will emit fugitive POC emissions from various components including valves, flanges, connectors, pumps, and compressors. The proposed upgrades to the Unit 240 Unicracker will include new sources of fugitive POC emissions; however, there will be no more than a negligible change in fugitive POC emissions from other existing units. Replacement equipment at existing units is expected to have approximately the same number of fugitive components. Additionally, piping changes within and between existing units are not expected to significantly affect the fugitive component count.

The number of new fugitive components for the CFEP is estimated based on pre-design drawing hand-count, comparison to existing units, ConocoPhillips experience in construction of similar units, and other estimation techniques. The estimated count of new fugitive components is divided into three service categories including gas, light liquid, and heavy liquid. **Table 3-6** provides an estimated fugitive component count for the modified Unicracker Process Unit, modified new Sulfur Plant, Deisobutanizer Unit, Reformer Unit, Product Blending, and Storage Tank No. 101.

Table 3-6 Fugitive Component Count

	Component Counts					
Unit	**Stream**	**Valves**	**Pumps**	**Connectors**	**Flanges**	**Other[1]**
Unit 240 Unicracker (S-307)(Unit 246)	Gas	295	0	295	590	1
	LL	419	2	419	838	1
	HL	547	3	547	1094	1
New Sulfur Plant Modifications (S1004 (Unit 235)	Gas	125	0	125	250	0
	LL	0	0	0	0	0
	HL	0	0	2	0	0
Unit 215 DIB Deisobutanizer (S-432)	Gas	0	0	0	0	0
	LL	20	0	160	40	0
	HL	0	0	0	0	0

Unit	Component Counts					
	Stream	Valves	Pumps	Connectors	Flanges	Other[1]
Unit 244 Reformer (S-308)	Gas	0	0	0	0	0
	LL	100	2	200	200	0
	HL	0	0	0	0	0
Unit 76 Product Blending (S-318)	Gas	0	0	0	0	0
	LL	100	4	100	200	0
	HL	100	4	100	200	0
New Tank No. 101	Gas	0	0	0	0	0
	LL	24	1	13	38	0
	HL	0	0	0	0	0

1. The "other" component type includes instruments, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes. This "others" component type should be applied for any component type other than connectors, flanges, open-ended lines, pumps, or valves.

LL – Light Liquid Stream

HL – Heavy Liquid Stream

These component counts were used to estimate fugitive POC and toxic air contaminant emission increases from the proposed CFEP. Pressure relief valves (PRVs) are not included in the fugitive component count because any new PRVs for the proposed CFEP will be connected to the refinery's blowdown system to control both fugitive leak and process upset emissions. There will not be any new open-ended lines for sampling or other purposes.

Fugitive POC emission estimates were calculated based on U.S. EPA Correlation Equations as presented in Table IV-3a of the February 1999 California Air Resources Board/California Air Pollution Control Officers Association (CARB/CAPCOA) document entitled California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities. This document is the accepted BAAQMD standard for estimating fugitive emissions.

For the purposes of this application, the maximum leak rate allowed by the BAAQMD (100 ppmv for valves, 500 ppmv for pumps, etc.) was used as the screening value (SV) in each Correlation Equation. Use of BAAQMD maximum leak rates results in a conservative emissions estimate because most fugitive components in the ConocoPhillips' leak detection and repair (LDAR) program have actual leak rates well below BAAQMD maximum leak rates.

The screening values used for valves, flanges, connectors, pump, and compressors and the corresponding correlation equations are shown in **Table 3-7**. This table also displays resulting emission factors in lbs/hr per source. Using the Correlation Equation approach, with the BAAQMD maximum leak rates, the resulting emission factors for each component type are the same for each type of service (gas, light liquid, and heavy liquid).

Table 3-7 Fugitive Component Emission Factors

Component Type/Service	Correlation Equation[1]	Screening Value, SV[2] (ppmv)	Resulting Emission Factor (kg/hr/source)	Resulting Emission Factor (lb/hr/source)
Valves/All	2.27E-6*(SV)^0.747	100	7.1E-05	1.6E-04
Connectors/All	1.53E-6*(SV)^0.736	100	4.5E-05	1.0E-04
Flanges/All	4.53E-6*(SV)^0.706	100	1.2E-04	2.6E-04
Pump Seals/All	5.07E-5*(SV)^0.622	500	2.4E-03	5.3E-03
Other[3]/All	8.69E-6(SV)^0.642	500	4.7E-04	1.0E-03

1. California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, February 1999.

2. Screening values assumed to be maximum leak rate allowed by BAAQMD, Regulation 8-18.

3. The "other" component type includes instruments, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes. This "others" component type should be applied for any component type other than connectors, flanges, open-ended lines, pumps, or valves.

Table 3-8 summarizes the total fugitive component emissions for all of the process units that are being modified.

Table 3-8 Total Fugitive Component Emissions

	Emissions		
	lb/hr	lb/day	ton/yr
Unicracker (Unit 240)246)	1.0	24	4.4
Sulfur Plant Modifications	0.096	2.32	0.42
Deisobutanizer (Unit 215 DIB)	0.029	0.71	0.13
Reformer (Unit 244)	0.10	2.3	0.43
Product Blending (Unit 76)	0.20	4.7	0.86
New Tank No. 101	0.020	0.48	0.089
Total	1.4	35	6.3

After construction of the new and modified units associated with the CFEP, an actual count of fugitive components will be conducted when the new components are added to the ConocoPhillips' LDAR program. This information will be provided to the BAAQMD to determine if any adjustments are needed for compliance with applicable requirements (i.e., a possible change in the quantity of required emission reduction credits).

The emission factors used to estimate TAC emissions from process unit fugitive components are based on service-weighted speciation data provided by ConocoPhillips. **Table 4-5** summarizes the profiles that are used in this application.

Table 4-5 Speciation Profiles for Fugitive Components

Unit	Weight Fraction of TACs in Process Unit Streams							
	Benzene	**n-Hexane**	**Toluene**	**Total Xylene**	**EB**[2]	**Naphthalene**	**1,2,4-TMB**[2]	**Cyclohexane**
Unicracker (Unit 246)[1]	0.003	0.0069	0.0041	0.0044	0.0014	0.00001	0	0
New Sulfur Plant (Unit 235)[1]	0	0	0	0	0	0	0	0
Deisobutanizer (Unit 215)[1]	0.011	0.12	0.015	0.001	0.01	0	0.001	0.02
Reformer (Unit 244)[1]	0.02	0.01	0.13	0.11	0.03	0.003	0.05	0.001
Product Blending (Unit 76)[1]	0.008	0.03	0.09	0.11	0.02	0.003	0.04	0.01
Tank No. 101[1]	0.0080	0.030	0.080	0.11	0.020	0.020	0.035	0.011

1. Based on service-weighted speciation provided by ConocoPhillips.
2. Compound abbreviations - EB: Ethylbenzene, TMB: Trimethylbenzene

Each speciation profile provides a weight percent breakdown of each chemical component that comprises total POC emissions. Therefore, fugitive TAC emissions for each component and service type are individually estimated by multiplying the weight percent of each toxic air contaminant (from the speciation profile) times the total fugitive POC emissions. **Table 4-6** presents a summary of TAC fugitive mass emissions.

Table 4-6 TAC Emissions from Fugitive Components

Unit	**POC**	**Benzene**	**n-Hexane**	**Toluene**	**Total Xylene**	**EB**[1]	**Naphthalene**	**1,2,4 - TMB**[1]	**Cyclohexane**
	lb/hr								
Unicracker (Unit 246)	1.0	0.0030	0.0069	0.0041	0.0044	0.0014	0.000010	0.00	0.00
New Sulfur Plant (Unit 235)	0.096	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deisobutanizer (Unit 215)	0.029	0.00032	0.0035	0.00044	0.00002	0.0003	0.00	0.00003	0.00059
Reformer (Unit 244)	0.10	0.0020	0.00098	0.013	0.011	0.0029	0.00029	0.0049	0.000098
Product Blending (Unit 76)	0.20	0.0016	0.0059	0.018	0.022	0.0039	0.00059	0.0079	0.0020
Tank No. 101	0.020	0.00016	0.00060	0.0016	0.0022	0.0004	0.00040	0.00070	0.00022

Total	1.4	0.0070	0.018	0.0365	0.039	0.009 0	0.0013	0.0135	0.0029
	lb/year								
Unicracker (Unit 246)	8770	26	61	36	38.6	12.3	0.1	0.0	0.0
New Sulfur Plant (Unit 235)	845	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
Deisobutanizer (Unit 215)	257	2.83	30.9	3.9	0.26	2.57	0.00	0.26	5.15
Reformer (Unit 244)	855	17.11	8.6	111.2	94.1	25.7	2.6	42.8	0.9
Product Blending (Unit 76)	1720	13.78	52	155.0	189.5	34.5	5.2	68.9	17.2
Tank No. 101	176	1.41	5.3	14.11	19.41	3.53	3.53	6.17	1.94
Total	12600	61	157	320	342	78	11	118	25

1. Compound abbreviations - EB: Ethylbenzene, TMB: Trimethylbenzene
2. Benzene and naphthalene emissions exceed the risk screening trigger level of 6.4 and 5.3 lb/year, respectively.

Turbines and HRSG
S352-S354, Combustion Turbines, S355-S357, HRSGs

The turbines/HRSGs will be a source of contemporaneous offsets for NOx for the CFEP project. The current annual limit for all six sources combined in 167 tons NOx in any consecutive 365-day period. The sources have CEMs that measure the concentration of NOx, CO, and O2. The flow is calculated using fuel flow monitors at each source and the F-factor method in 40 CFR 60, Appendix A, Method 19. On October 2, 2006, ConocoPhillips submitted data showing that the actual annual average NOx emissions for the combined equipment were 101.9 tons per year. ConocoPhillips has proposed to decrease the NOx emissions by 22.1 tons per year to 79.8 tons per year. The reduction will be confirmed by CEM monitoring.

Dissolved Air Flotation
S1007, Dissolved Air Flotation Unit (DAF)

An air flotation unit, is defined by BAAQMD Regulation 8-8-209 as:

> Any device, equipment, or apparatus in which wastewater is saturated with air or gas under pressure and removes floating oil, floating emulsified oil, or other floating liquid precursor organic compounds by skimming. Also included in this definition are: induced air flotation units and pre-air flotation unit flocculant sumps, tanks, or basins.

S1007, Dissolved Air Flotation Unit, accepts wastewater from the oil-water separator and separates remaining oil by bubbling air through the unit, adding a flocculant to aid separation, and skimming the oil and flocculant from the unit. The wastewater is then ready for processing by the biological treatment units.

BAAQMD Regulation 8-8-307 requires control of air flotation units with covers or organic compound recovery systems with a combined collection and destruction efficiency of at least 70 percent by weight. Section 307.1 allows the units to have atmospheric vents.

Based on samples gathered by BAAQMD in August 2005 and June 2006, and on flow testing that ConocoPhillips performed in June 2006, the facility has concluded that the DAF atmospheric vents emit up to 37 tons POC per year. The District has concluded using the model TOXCHEM during the 2004 rulemaking for BAAQMD Regulation 8, Rule 8, that the emissions from the channel and weir are about 8 tons per year.

The facility has proposed to control the source with a 440,000 btu/hr thermal oxidizer, A49, to obtain 44.1 tons of contemporaneous PCO offsets. The facility will be required to show by source test that they will capture and destroy 44.1 tons per year or they will be required to supply the offsets from another source. If the offsets are obtained from a banking certificate, ConocoPhillips will have to provide them at a 1:1.15 ratio.

Following are calculations of the DAFs secondary emissions.

DAF Vent Emissions

Pollutant	Pre-Controlled Emissions (tons/yr)	% of Year that Thermal Oxidizer is in Operation (shutdown 1 wk per year)	Post Controlled Emissions (ton/yr)	Difference
VOC	45	0.98	0.92	-44.08
NOX	0	0.98	0.21	0.21
H2S	0.63	0.98	0.01	-0.62
SO2	0	0.98	1.2	1.2

CO Emissions

Thermal Oxidizer duty	440000		
NG Heat Value	1020	Btu/scf	
NG Flow=	7.19	scfm	
NG Heat Content=	0.44	MMBtu/hr	(A small boiler per AP 42 Table 1.4-1)
CO EF=	84	lb/MMscf (per AP 42 Table 1.4-1 for small boilers)	

CO Emissions (lb/hr)=(NG Flow)*(CO EF)/1000000*60*(% year in operation)

CO Emissions =	0.036	lb/hr
CO Emissions =	0.85	lb/day
CO Emissions =	0.16	TPY

PM10 Emissions

NG Flow=	7.19	scfm
PM10 EF=	7.6	lb/MMscf (per AP 42 Table 1.4-2)

PM10 Emissions (lb/hr)=(NG Flow)*(PM10 EF)/1000000*60*(% year in operation)

PM10 Emissions =	0.0032	lb/hr
PM10 Emissions =	0.077	lb/day
PM10 Emissions =	0.014	TPY

DAF SO_2 Emissions

	Current H_2S Emissions (lb/d)	SO_2 emissions (if combusted) (lb/d)	
Flow rate Vent #6	2.21	4.2	
Flow rate Vent #7	0.34	0.6	
Flow rate Vent #8	0.61	1.1	
Flow rate Vent #9	0.29	0.5	
		6.5	lb/d
		2364	lb/yr

Paved Roads

ConocoPhillips provided the following emission estimates and the District has found them to be acceptable.

Paved Road Emissions

	Estimated Project Change	**Estimated Daily Project Change**
Commodity	Trips/time period	Trips/day
Raw Material Delivery:		
Sodium hydroxide	+1 trip/month	0.033
Aqueous ammonia	+2 trip/month	0.067
Amine	+2 trips/year	0.0055
Feedstock additives	+2 trips/month	0.067
Stretford solution	0 trips/year	0
Feed crude oil	no change	0
Product shipping:		
Molten sulfur	+9 trips/day	9
Waste Shipping		
Sulfur/vanadium		
Stretford waste	0 trip/day	0
Spent catalyst	+12 trips/year[1]	0.033
	Total	9.2

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 (lb/VMT) = k (sL/2)0.65(W/3)1.5(1-P/4N)

E = emission rate
VMT = "vehicle miles traveled" = (4 mile/trip)* 9.2
36.8 miles/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 reduced trip (liquid oxygen 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)* 36.8 6.3 lbs/day
= 1.1 ton/yr

Locomotive Emissions

ConocoPhillips provided the following emission estimates and the District has found them to be acceptable.

Locomotive Emission Calculations

Emission Factors (g/gal)

HC	CO	NOx	SOx	PM
10.1	27.4	185.6	13.6	6.4

Rail cars

3

Distance Traveled (miles)

42

Weight Per Railcar (pounds)

100000

Combined Weight of Railcars and Butane (pounds)

263000

Conversion Factors

0.001296 gal/ton mile

0.0005 ton / pound

Emissions (g) (Empty Railcars)

HC	CO	NOx	SOx	PM
82.46448	223.7155	1515.387	111.0413	52.25472

Emissions (lb) (Empty Railcars)

HC	CO	NOx	SOx	PM
0.181421856	0.492174	3.333851	0.244291	0.11496

Emissions (g) (Full Railcars)

HC	CO	NOx	SOx	PM
216.8816	588.3718	3985.467	292.0386	137.4299

Emissions (lb) (Full Railcars)

HC	CO	NOx	SOx	PM
0.477139481	1.294418	8.768028	0.642485	0.302346

Emissions (lb/day)

HC	CO	NOx	SOx	PM	Benzene	Formaldehyde
0.66	1.79	12.10	0.89	0.42	0.013	0.097

Emissions (lb/year)

HC	CO	NOx	SOx	PM	Benzene	Formaldehyde
240.4	652.1	4417.2	323.7	152.3	4.8	35.4

Emissions (TPY)

HC	CO	NOx	SOx	PM	Benzene	Formaldehyde
0.12	0.33	2.21	0.16	0.076	0.0024	0.018

Truck Emissions

The truck emissions can be found in the Draft Environmental Impact Report that was prepared by Contra Costa County.

Facility A0022, ConocoPhillips Carbon Plant
S2, Kiln

S2 will be a source of contemporaneous offsets for SO2 for the CFEP project. There is currently no annual limit for SO2 for the source. The source is subject to the limits in BAAQMD Regulation 9-310.2, which are a concentration limit of 400 ppm by volume and 250 lb/hr, whichever is more restrictive. The source is also subject to a throughput limit of 262,800 tons coke per year and natural gas limits of 5 million therms at the kiln and 2.6 million therms at A1, Pyroscrubber.

The source has a CEM that measures the concentration of SO2 and flow. On October 17, 2006, ConocoPhillips submitted data showing that the actual annual average SO2 emissions were 791 tons per year. ConocoPhillips has proposed to decrease the SO2 emissions by 42 tons per year to 749 tons per year. The reduction will be confirmed by CEM monitoring.

ConocoPhillips will lower the SO2 emissions by injecting sodium bicarbonate into the stream of combustion products prior to the baghouse. The sodium bicarbonate absorbs some of the SO2. This system is in place and is currently being used to ensure that the limits in BAAQMD Regulation 9-310.2 are met. ConocoPhillips will simply inject a higher amount of sodium bicarbonate than is currently being used.

S2 will also be a source of actual reductions for PM10 for the CFEP project. For the purposes of CEQA, Contra Costa County did not agree to emission reduction credits were acceptable and requested that ConocoPhillips make "real-time" reductions in PM10. ConocoPhillips will reduce the emissions of PM10 by upgrading the bags in the kiln baghouse. The new bags will improve control without increasing the pressure drop beyond the baghouse specifications. The facility has 3 annual source tests for particulate that establish the current emission levels. The facility will demonstrate the reduction using annual source tests.

The reduction is not eligible for contemporaneous offsets because it is not in excess of the reductions achieved by the source using Reasonably Available Control Technology (RACT) as required by BAAQMD Regulation 2-1-201. RACT has not been established for this source, but the District estimates that it may be about 0.01 or 0.02 gr/dscf. The source is currently at about 0.04 gr/dscf. The source is in compliance with the BAAQMD Regulation 6-310 level of 0.15 gr/dscf. The facility may apply for emission reduction credits for a portion of this reduction if the RACT level is established.

APPENDIX B

Sulfuric Acid Mist Calculations

Summary of Emission Increases		
Non SRU Total Emission Increases		
New Unit 246 HGO Heater	0.36	TPY
New SMR Furnace in Hydrogen Plant	0.43	TPY
Increased Heater Utilization	0.20	TPY
Total Non SRU Emission Increases	**0.99**	**TPY**
Max Possible New SRU U235 Emissions	**5.65**	**TPY**
Max Possible New SRU U235 Emissions rate	**0.0087**	**gr/dscf (@ 0% O2)**

based on SO3/SO2 conversion in heaters/boilers of 5%

max possible derived such that CFEP project emissions are <7 TPY

Estimated New SRU U235 Emission Rate **4.89** **TPY**

based on average of emission rates from existing SRUs

1. New SRU-235

1) Based on averaged emissions source testing data for existing SRUs
2) Volumetric flow data from Fluor. Used T and moisture data from source testing to convert to dscf
3) 7000 gr = 1lb
4) Assuming emissions from stacks are at standard pressure (1 atm)

H2SO4 (mass)= SO3 (mass)*(MW_H2SO4)/(MW_SO3)

MW_SO3	80.06	g/mole
MW_H2SO4	98.08	g/mole

Vflow (Fluor)= 1.04 mmdscf/hr (at 0% H20 and O2).
(Obtained from Fluor in email to Valerie Uyeda dated April 27, 2006)
Operation Time = 8760 hours/yr

Cavg_SO3 = 0.00613 gr/dscf (@ 0% O2 and H20)
(based on averaged source test data for existing SRUs)

	lbs/yr	TPY
Estimated SO3 emissions (existing source test rate)	7982.45	3.99

	Emission Increases Based on Avg. Source Testing Data	
	lbs/yr	**TPY**
H2SO4=	9779.14	4.89

3. New Unit 246 HGO Heater

1) Ratio of SO3/SO2 conversion is represented as 0.05 based upon guidance developed originally in EPA AP40 and used as industry standard for boilers and heaters

H2SO4(mass)= (mass SO2)*(SO2 fraction converted to H2SO4)*(MW_H2SO4)/(MW_SO2)

MW_SO2	64.06	g/mole
MW_H2SO4	98.08	g/mole

SO2 Total = 4.7 TPY

H2SO4 Total= **0.36** TPY

4. New SMR Furnace in Hydrogen Plant

1) Ratio of SO3/SO2 conversion is represented as 0.05 based upon guidance developed originally in EPA AP40 and used as industry standard for boilers and heaters

H2SO4(mass)= (mass SO2)*(SO2 fraction converted to H2SO4)*(MW_H2SO4)/(MW_SO2)

MW_SO2	64.06	g/mole
MW_H2SO4	98.08	g/mole
SO2 Total =	5.6	TPY
H2SO4 Total=	**0.43**	TPY

5. Increased Heater Utilization

1) Ratio of SO3/SO2 conversion is represented as 0.05 based upon guidance developed originally in EPA AP40 and used as industry standard for boilers and heaters

H2SO4(mass)= (mass SO2)*(SO2 fraction converted to H2SO4)*(MW_H2SO4)/(MW_SO2)

MW_SO2	64.06	g/mole
MW_H2SO4	98.08	g/mole
SO2 Total =	2.6	TPY
H2SO4 Total=	**0.20**	TPY

APPENDIX C

PSD AIR QUALITY IMPACT ANALYSIS

APPENDIX d

ConocoPhillips Analysis of BACT for NOx and PM10

Following is ConocoPhillips' review of Best Available Control Technology for S45, Heater, S1004, Sulfur Recovery Unit, and Facility B7149, S2, Heater from Prevention of Significant Deterioration Application submitted on June 2, 2006

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

This section addresses BACT requirements for the proposed ConocoPhillips CFEP, as well as the related new Hydrogen Plant on the Refinery site to be owned and operated by Air Liquide Large Industries U.S. LP.

BAAQMD Rule 2-2-301 requires BACT to be applied to:

"…any new or modified source which results in an emission from a new source, or an increase in emissions from a modified source, and which has the potential to emit 10.0 pounds or more per highest day of precursor organic compounds (POC), non-precursor organic compounds (NPOC), nitrogen oxides (NO_x), sulfur dioxide (SO_2), PM_{10}, or carbon monoxide (CO)."

Proposed controlled emission levels to meet BAAQMD BACT requirements, from recent BAAQMD BACT determinations and the BAAQMD BACT Guidelines (BAAQMD 2005) can be found in the *Clean Fuels Project Application for Authority to Construct and Significant Revision to Major Facility* (ConocoPhillips 2006) and the *Hydrogen Plant Project Application for Authority to Construct and Major Facility Review Permit* (Air Liquide 2005).

Included in BAAQMD Regulation 2, Rule 2, are provisions that implement federal PSD requirements. USEPA policy includes a "top-down" BACT analysis for all pollutants emitted in PSD-significant quantities from new and modified emissions. As described in Section 3.0, PSD requirements apply to NO_x and PM_{10} in this proposed action. To supplement the BACT analysis presented in the above-referenced BAAQMD Authority to Construct (ATC) Applications, the remainder of this section presents "top-down" BACT analyses for the proposed new and modified sources of NO_x and $PM_{10,}$ based on the USEPA RACT/BACT/LAER Clearinghouse (RBLC), California Air Resources Board (CARB) BACT Clearinghouse, and available information on other recently issued permits.

USEPA guidance for a "top-down" BACT analysis requires reviewing all possible control options starting at the top level of control efficiency. In the course of the BACT analysis, one or more options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, or environmental impacts on a case-by-case (site-specific) basis. The steps required for a "top-down" BACT review are:

1. Identify All Available Control Technologies
2. Eliminate Technically Infeasible Options
3. Rank Remaining Technologies
4. Evaluate Remaining Technologies (in terms of economic, energy, and environmental impacts)
5. Select BACT (the most efficient technology that cannot be rejected for economic, energy, or environmental impact reasons is BACT)

4.1 U246 HEAVY GAS OIL (HGO) FEED HEATER

The proposed new U246 HGO Feed Heater supporting the modified Unit 240/246 Unicracker is proposed to be fired on refinery fuel gas (RFG), with natural gas as a backup fuel. The new HGO Feed Heater would be a natural draft process heater rated at 85 million British thermal units per hour (MMBtu/hr).

4.1.1 NO_x BACT – U246 HGO Feed Heater

1. Identify All Available Control Technologies

Table 3 lists the technologies identified for controlling NO_x emissions from process heaters fired on RFG or natural gas.

Table 3 NO_x Control Technologies

Control Technology
No Controls (Base Case)
Water/Steam Injection
Selective Non-Catalytic Reduction (SNCR)
Combustion Controls (Low-NO_X Burners)
Selective Catalytic Reduction (SCR)
Low-NO_X Burners and SNCR
Low-NO_X Burners and SCR
SCONOx

2. Eliminate Technically Infeasible Options

All the control methods identified in Table 3 are considered technically feasible for a process heater fired on RFG, except SCONOx™, SNCR, and water/steam injection.

SCONOx. SCONOx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO_x emissions. The catalyst oxidizes carbon monoxide (CO) to carbon dioxide (CO_2), and nitric oxide (NO) to NO_2. The CO_2 is exhausted while the NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is passed periodically across the surface of the catalyst to convert the KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2), thereby regenerating the K_2CO_3 coating for further absorption. The H_2O and N_2 are exhausted.

SCONOx has not been demonstrated on RFG-fired process heaters (Arizona Department of Environmental Quality [ADEQ] 2005). It has only been demonstrated on combustion sources burning exclusively natural gas. The performance of SCONOx is sensitive to sulfur in the exhaust stream. In addition, the heat ratings on natural gas burners demonstrated with SCONOx are lower than the proposed HGO Feed Heater. Thus, there are significant technical differences between the proposed source and those few sources where SCONOx has been demonstrated in practice. These preclude a finding that SCONOx has been demonstrated to function efficiently on sources identical or similar to the proposed process heater.

<u>Selective Non-Catalytic Reduction (SNCR)</u>. SNCR is a post-combustion NO_x control technology based on the reaction of urea or ammonia (NH_3) and NO_x. SNCR involves injecting urea/NH_3 into the combustion gas path to reduce the NO_x to nitrogen and water. This is described by the following chemical equations:

$$2\ CO\ (NH_2)_2\ (\textit{urea}) + 4\ NO + O_2 \rightarrow 4\ N_2 + 2\ CO_2 + 4\ H_2O$$
$$4\ CO\ (NH_2)_2 + 2\ NO_2 + 4\ O_2 \rightarrow 5\ N_2 + + 4\ CO_2 + 8\ H_2O$$

$$4\ NH_3\ (\textit{ammonia}) + 4\ NO + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$
$$4\ NH_3 + 2\ NO_2 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Temperatures ranging from 1,200°F to 2,000°F are required for optimum SNCR performance. Operation at temperatures below this range results in NH_3 slip, while operation above this temperature range results in oxidation of NH_3, forming additional NO_x. Exhaust temperatures of process heaters are typically below the optimum temperature range. In addition, the urea/ammonia must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO_x reduction.

SNCR can only be used in induced draft process heaters because of the need to recirculate the flue gas. The HGO Feed Heater will be a natural draft process heater. In addition, existing information on SCNR systems indicate they achieve NO_x reductions ranging from 30 to 75 percent (USEPA 2001), thus SNCR is an inferior control technology to either SCR or modern combustion controls for an

RFG-fired process heater. Therefore, SNCR is considered infeasible for this review.

Water/Steam Injection. The injection of steam or water into the combustion zone can decrease peak flame temperatures, thus reducing thermal NO_x formation. Steam injection is predominantly used with gas turbines. There is little data available to document the effectiveness of water/steam injection for process heaters and no application of this type could be found. Steam injection has been specified as a control method for boilers on a very limited basis. Only one was listed in the USEPA RBLC database during the ADEQ's recent review of the Arizona Clean Fuels Yuma, LLC project (ADEQ 2005). This review showed a controlled emission rate higher than low NO_x burners produced today. Additionally, there are operating issues concerning flame stability using low NO_x burners with steam injection. Therefore, water/steam injection is considered infeasible for this review.

3. Rank Remaining Technologies

Technically feasible NO_x control technologies are listed in Table 4 with typical emission levels, ranked from most efficient to least efficient.

Combustion Controls. Combustion controls reduce NO_x emissions by controlling the combustion temperature or the availability of oxygen (O_2). These are referred to as "low NO_x burners" or "ultra-low NO_x burners." There are several designs of low/ultra-low NO_x burners currently available. These burners combine two NO_x reduction steps into one burner, typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment.

In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel-rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. This design is predominantly used with liquid fuels.

Table 4 NO_x Control Hierarchy for Process Heaters Fired on Refinery Fuel Gas

Technology	Typical Emission Level	
	ppmv[1]	**lb/MMBtu[2]**
Combustion Controls and SCR[3]	7	0.0085
Selective Catalytic Reduction (SCR)	18	0.022
Combustion Controls	29	0.035
No Controls[4]	89	0.11

Source: *Petroleum Refinery Tier 2 BACT Analysis Report*, *Final Report* (EPA, 2001).

[1] Parts per million by volume (ppmv), dry basis, corrected to 3% oxygen.

[2] Pounds (lbs) of NO_x produced per MMBtu of fuel heat input.

[3] Recent data show a range of values, with 7 ppmv representing the low end of current permitted levels on RFG-fired refinery heaters. See discussion of current BACT determinations in text for more details.

[4] Emission level shown is for a natural draft heater; an induced draft heater would typically have higher uncontrolled NO_x levels, on the order of 179 ppmv at 3% O_2, dry (USEPA 2001).

In staged fuel burners with IFGR, fuel pressure induces the IFGR, which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominantly used for gas fuel applications.

The range of performance achieved in practice for the best combustion controls is 25 to 29 ppmv at 3% O_2, dry (0.03 to 0.035 lb/MMBtu), with the upper end of range representing heaters firing gas with high hydrogen content (USEPA 2001). Burners that could achieve 10 ppmv or lower are under development, but are not currently available for process heaters.

RFG is high in hydrogen content, so for heaters burning RFG or a mixture of RFG and natural gas, the upper end of the demonstrated range (29 ppmv at 3% O_2, dry, or 0.035 lb/MMBtu) would be appropriate as the achievable performance level for combustion controls on RFG-fired process heaters.

Selective Catalytic Reduction (SCR). SCR is a process that involves post-combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging, ammonia slip emissions, and design of the NH_3 injection system. The most common catalysts are composed of vanadium, titanium, molybdenum, and zeolite. Sulfur dioxide and sulfur trioxide are generated in the flue gas when sulfur-containing compounds in fuel are combusted. Catalyst systems promote partial oxidation of sulfur dioxide (from sulfur and mercaptans in the fuel) to sulfur trioxide, which combines with water to form sulfuric acid, causing corrosion over time. In addition, sulfur trioxide and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled, which over time can accumulate on the catalyst causing “plugging” and catalyst deterioration, often referred to as “fouling.” These effects can be minimized by proper operation, including:

Controlling the amount of sulfur in the fuel.

Using a properly designed ammonia injection system to maximize the efficient mixing of ammonia and flue gas without colder surfaces present on which ammonium salts can condense.

Operating with the lowest amount of ammonia needed to achieve the desired performance. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which necessarily results in ammonia slip. Thus, an emissions tradeoff between NO_x and ammonia occurs in high NO_x reduction applications.

Operating at temperatures above the dew point of ammonium salts and sulfuric acid.

Optimal operating temperatures vary by catalyst but generally range from 500 to 800°F. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby adding NO_x emissions) or ammonium nitrate. Operating below the optimal temperature increases ammonia slip and catalyst fouling. Refinery process heaters typically operate in the range of 450 to 700°F, thus would be expected to operate above the dew point of ammonium salts and sulfuric acid to minimize fouling and corrosion. SCR systems have been used on process heaters burning mixtures of RFG and natural gas.

SCR systems achieve 80 to 90 percent reductions in NO_x emissions (USEPA 2001). The 90 percent reduction is relative to an uncontrolled induced draft heater since the higher NO_x emissions (approximately 179 ppmv at 3% O_2, dry, or 0.22 lb/MMBtu) versus a natural draft heater (approximately 89 ppmv at 3% O_2, dry, 0.11 lb/MMBtu) provides a greater driving force for increased mass transfer and also enhances the SCR’s mechanical draft requirements. This yields an outlet NO_x emission level of approximately 18 ppmv at 3% O_2, dry, or 0.011 lb/MMBtu. For a natural draft heater, maximum SCR control efficiency is on the order of 80 percent due to lower uncontrolled emission rates, yielding approximately the same controlled NO_x emission rate. Thus, a typical achievable performance level for SCR systems on RFG-fired process heaters is 18 ppmv at 3% O_2, dry, or 0.011 lb/MMBtu.

SCR and Combustion Controls. This control option uses SCR downstream of combustion controls to reduce NO_x emissions. With this combination, the inlet NO_x level to the SCR is lower, so lower outlet NO_x can be achieved. However, the SCR may not achieve the same percent reduction performance compared to no upstream combustion controls because of the lower NO_x inlet levels. As is discussed further below, a review of the USEPA RBLC and CARB BACT Clearinghouse showed permit limits of 7 ppmv NO_x at 3% O_2, dry, as the lowest level achieved in practice on refinery process heaters with SCR and combustion controls fired on a combination of RFG and natural gas. Therefore, the achievable performance level for SCR and combustion controls on RFG-fired process heaters is 7 ppmv at 3% O_2, dry, or about 0.0085 lb/MMBtu.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, the top technically feasible control option, SCR with combustion controls, is the proposed control technology. Therefore, the selection of BACT consists of establishing the lowest controlled NO_x emission level achievable with this control technology, taking into consideration the lowest controlled NO_x emissions currently achieved in practice, and if necessary, energy, environmental and economic impacts between different potential controlled emission levels using this technology.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted. These reviews resulted in the lowest NO_x emission limits for refinery heaters fired on RFG/natural gas found in the South Coast Air Quality Management District (SCAQMD). A review of the BACT Determinations published by the SCAQMD provided further details.

There were three SCAQMD BACT Determinations for 7 ppmv NO_x at 3% O_2, dry, documented in the USEPA *Petroleum Refinery Tier 2 BACT Analysis Report* (USEPA 2001) for process heaters burning natural gas or a combination of RFG and natural gas. These were for: (1) Chevron El Segundo Refinery (Permit No. D64697, D62860, D64621); (2) TOSCO Refinery, Wilmington (Application 326118);[1] and (3) CENCO Refinery, Santa Fe Springs (Application 352869).

The ADEQ (2005) recently issued a permit for a similar project, Arizona Clean Fuels Yuma, LLC (ADEQ Permit Number 1001205). In their top-down BACT finding issued on 3 February 2005, the ADEQ summarized the following findings for the highest efficiencies achievable with SCR and combustion controls on RFG-fired process heaters (all 3-hour averages):

High-Efficiency SCR:

NO_x: 0.0085 lb/MMBtu (7 ppmv at 3% O_2, dry)[2]

Moderate-Efficiency SCR:

NO_x: 0.0125 lb/MMBtu (10 ppmv at 3%O_2, dry)

The ADEQ concluded for Arizona Clean Fuels Yuma LLC that the beneficial environmental impacts of increased NO_x control for the high-efficiency SCR was

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[1] Noted in the SCAQMD BACT Determinations to be for a 460-MMBtu/hr Hydrogen Reforming Furnace also combusting Pressure Swing Absorption (PSA) off gas.

[2] Although the NO_x permit limit for Arizona Clean Fuels Yuma LLC is presented as ppm corrected to 3% O_2, dry, the ADEQ Technical Report presents results in ppm corrected to 0% O_2, dry. These have been converted to 3% O_2, dry, for the purposes of the ConocoPhillips analysis.

outweighed by adverse environmental impacts of increased ammonia slip. Therefore, the NO_x emissions level found to be BACT was 10 ppmv at 3% O_2, dry.

The proposed NO_x emission limit for the ConocoPhillips HGO Feed Heater is 7 ppmv at 3% O_2, dry. This is equivalent to the high-efficiency SCR option that was ruled out by ADEQ, and matches the lowest NO_x emission limit achieved in practice. No further energy, environmental, or economic impact assessment is needed.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as SCR with combustion controls (low NO_x burners) at 7 ppmv at 3% O_2, dry, or 0.0086 lb/MMBtu.[3]

4.1.2 PM_{10} BACT – U246 HGO Feed Heater

1. Identify All Available Control Technologies

Table 5 lists the control technologies identified for controlling PM_{10} emissions from process heaters fired on natural gas or RFG.

Table 5 PM_{10} Control Technologies

Control Technology
Good Combustion Practice
Cyclone
Wet Gas Scrubber
Electrostatic Precipitator
Baghouse/Fabric Filters

Good Combustion Practice. By maintaining heaters in good working order and limiting the sulfur in the feed fuels, PM_{10} emissions are controlled.

Cyclone. A cyclone operates on the principle of centrifugal force. Exhaust gas enters tangentially at the top of the cyclone and spirals towards the bottom. As the gas spins, heavier particles hit the outside wall and are collected at the bottom. Cleaned gas escapes through an inner tube.

Wet Gas Scrubber. A wet gas scrubber uses gas/liquid contacting to remove particles primarily by inertial impaction on liquid droplets, followed by collection of the larger liquid droplets as liquid waste.

Electrostatic Precipitator (ESP). An ESP uses an electric field to charge and collect particles in a gas stream, followed by collection of the particles on oppositely charged plates.

[3] Slight difference from the previous conversions from 7 ppmv at 3% O_2, dry, due to fuel heat value assumptions and/or rounding.

Baghouse/Fabric Filter. A baghouse is a metal housing containing many fabric bags. A partial vacuum pulls the dirty air through the fabric bags, filtering the particles from the exhaust stream.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM_{10} emissions from gas-fired heaters. The other technologies are not used because of inherently low PM_{10} emissions from gaseous fuel combustion. A cyclone would be ineffective in capturing the extremely small particles generated from gaseous fuel combustion, and costs associated with designing the other add-on systems to capture minute particles in low concentrations would be economically infeasible. This is a well-accepted finding of all past BACT determinations for the control of PM_{10} from combustion of gaseous fuels.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. Findings were the same as summarized by the ADEQ for the Arizona Clean Fuels Yuma LLC (ADEQ 2005). ADEQ proposed a PM_{10} emission limit of 0.0075 lb/MMBtu as representative of good combustion practice with gas-fired process heaters, based on the AP-42 emission factor (USEPA 1995a et seq.) for natural gas combustion and typical natural gas heat content. This is consistent with the lowest level achieved in practice.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM_{10} BACT is proposed as good combustion practice. The USEPA AP-42 natural gas combustion factor was adjusted with the estimated fuel heat content of the proposed RFG/natural gas mixture to calculate a proposed PM_{10} BACT emission level of
0.0057 lb/MMBtu.

4.2 HYDROGEN PLANT REFORMER Furnace

The proposed new Hydrogen Plant Steam Methane Reformer (SMR) Furnace is proposed to be fired on a mix of approximately 85 percent Pressure Swing Absorption (PSA) off gas and 15 percent RFG/natural gas.

4.2.1 NO_x BACT – Hydrogen Plant Reformer Furnace

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 3 of Section 4.1.1.

2. Eliminate Technically Infeasible Options

All the control methods identified in Table 3 are considered technically feasible for a Hydrogen Plant Reformer fired on the proposed mix of fuels, except SCONOx, SNCR, and water/steam injection, for the same reasons provided for a refinery process heater in Section 4.1.1.

3. Rank Remaining Technologies

Technically feasible NO_x control technologies are the same as listed in Table 4 of Section 4.1.1. Since the proposed mix of fuels includes natural and RFG, the emission levels presented in Table 4 can still be considered typical for this application. Inclusion of PSA off gas, however, affects combustion characteristics, and hence, can impact the actual achievable emission levels. Consideration of PSA off gas is included in the following BACT evaluation discussion.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, the top technically feasible control option, SCR with combustion controls, is the proposed control technology. Therefore, the selection of BACT consists of establishing the lowest controlled NO_x emission level achievable with this control technology, taking into consideration the lowest controlled NO_x emissions currently achieved in practice, and if necessary, energy, environmental and economic impacts between different potential controlled emission levels using this technology.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted. These reviews resulted in the lowest NO_x emission limits for hydrogen reformer furnaces fired on PSA off gas and RFG/natural gas found in the SCAQMD. A review of the SCAQMD BACT Determinations provided further details.

PSA off gas is high in hydrogen content, and therefore has the potential to form less NO_x and PM_{10}. There were five SCAQMD BACT Determinations for hydrogen reformer furnaces. In reverse chronological order, these NO_x emission limits were: (1) Chevron El Segundo Refinery (Application 411357, 5/19/2004, 5 ppmv at 3% O_2, dry); (2) Praxair, Ontario (Application 389926, 7/17/2002, 5 ppmv at 3% O_2, dry); (3) TOSCO Refinery, Wilmington (Application 326118, 9/9/1999, 7 ppmv at 3% O_2, dry); (4) Chevron El Segundo Refinery (Application 341340, 7/14/1999, 5 ppmv at 3% O_2, dry) and (5) Air Products and Chemicals, Inc. (Application 337979, 6/16/1999, 5 ppmv at 3% O_2, dry).

The proposed NO_x emission limit for the Air Liquide Hydrogen Reformer is 5 ppmv at 3% O_2, dry. Since this is the lowest NO_x emission limit achieved in practice, no further energy, environmental, or economic impact assessment is needed.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as SCR with combustion controls (low NO_x burners) at 5 ppmv at 3% O_2, dry, or 0.0058 lb/MMBtu.

4.2.2 PM_{10} BACT – Hydrogen Plant Reformer Furnace

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 5 of Section 4.1.2.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM_{10} emissions from gas-fired heaters, as described in Section 4.1.2.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. No applicable PM_{10} BACT emission levels were found. The five SCAQMD BACT Determinations for hydrogen reformer furnaces did not include PM_{10}, thus, from Section 4.1.2, a PM_{10} emission limit of 0.0075 lb/MMBtu is representative of good combustion practice with gas-fired process heaters. In this case, the proposed Hydrogen Reformer will fire up to 85 percent PSA off gas, which produces less PM_{10} emissions due to high hydrogen content. It is proposed that with the inclusion of PSA off gas, a reasonable PM_{10} emission limit would be half the amount produced by natural gas alone, or 0.0037 lb/MMBtu.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM_{10} BACT is proposed as good combustion practice at 0.0037 lb/MMBtu. The proposed PM_{10} emissions level is consistent with the lowest level achieved in practice, with further consideration given for the PSA off gas in the fuel mixture.

4.3 SULFUR RECOVERY UNIT (SRU)

The proposed new Unit 235 SRU will be a closed Claus process supported by an amine-based TGTU to convert unreacted hydrogen sulfide (H_2S) from the Claus process. The TGTU is also a closed process. Any unreacted H_2S in the tail gas passing through the TGTU will be oxidized in a new tail gas incinerator, which is the emission point for the process. Vents from the new sulfur loading rack will also be routed to the tail gas incinerator for oxidation of H_2S. Therefore, BACT for the SRU was assessed for NO_x and PM_{10} from the tail gas incinerator.

4.3.1 NO_x BACT – SRU Tail Gas Incinerator

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 3 of Section 4.1.1.

2. Eliminate Technically Infeasible Options

The only option listed in Table 3 that is technically feasible for an SRU tail gas incinerator is combustion control with low-NOx burners. The other technologies are either based on lowering flame temperature, which is not compatible with the primary function of the incinerator (i.e., efficient oxidation of reduced sulfur compounds), or add-on controls that have not been demonstrated technically feasible for a thermal oxidizer. There are significant technical differences between thermal oxidizers and the combustion sources for which these technologies have been demonstrated in practice.

3. Rank Remaining Technologies

The only technically feasible NO_x control technology is combustion control with low-NOx burners.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, a review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for the most efficient low-NOx burners achieved in practice for tail gas thermal oxidizers for SRU TGTUs. These reviews resulted in the lowest NO_x emission limit achieved in practice as 42.2 ppmv @ 7% O_2, dry, or 0.0667 lb/MMBtu, associated with the recently issued PSD permit for the SRU TGTU at the ConocoPhillips Ferndale Refinery. This level, for a unit currently in operation, is similar to the 0.06 lb/MMBtu level proposed by the ADEQ for the Arizona Clean Fuels Yuma LLC (ADEQ 2005), a facility not yet in operation.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as combustion control with low-NOx burners at 42.2 ppmv at 7% O_2, dry, or 0.0667 lb/MMBtu.

4.3.2 PM_{10} BACT – SRU Tail Gas Incinerator

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 5 of Section 4.1.2.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM_{10} emissions from the combustion of gaseous fuels, as described in Section 4.1.2.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. No applicable PM_{10} BACT emission levels were found. It is proposed that reasonable PM_{10} emission limit would be the amount produced by natural gas alone, or 0.0075 lb/MMBtu.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM_{10} BACT is proposed as good combustion practice at 0.0075 lb/MMBtu. The proposed PM_{10} emissions level is consistent with the lowest level achieved in practice.

4.4 New Flaring

The proposed project includes a new Hydrogen Plant flare that would operate during planned and unplanned events. The shutdown and startup of the new Unit 240/246 would also cause new flaring emissions from the existing Main Flare, but this is estimated to occur only once every three years.

Flares operate primarily as air pollution control devices, but are nonetheless emission sources subject to BACT analyses. The technically feasible control options for emissions of all pollutants from flares are equipment design specifications and work practices: minimizing exit velocity, ensuring adequate heat value of combusted gases, and minimizing the quantity of gases combusted. Each of these control options is technically feasible and is required for the operation of emergency flares at the refinery.

The equipment design criteria for emergency flares are based largely on the parallel requirements set forth in the NSPS regulations (40 CFR 60.18) and the National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations (40 CFR 63.11). These include a maximum allowable exit velocity, a requirement for smokeless operation, and a minimum allowable net heating value for gases combusted in the flares. ConocoPhillips is not aware of any more stringent requirements imposed on flares at any other petroleum refinery, nor any other technically feasible control options for emissions of any pollutants from flares.

APPENDIX E

Kb letter

Appendix F

PSD Re-delegation Agreement.

Appendix g

CEQA Findings

CONOCOPHILLIPS – SAN FRANCISCO REFINERY
PROPOSED CLEAN FUELS EXPANSION PROJECT

FINDINGS AND SUPPORTING FACTS REGARDING THE ENVIRONMENTAL IMPACT REPORT

ConocoPhillips - San Francisco Refinery (The Refinery) has proposed to construct the Clean Fuels Expansion Project (CFEP) at its Rodeo Refinery. The CFEP includes new equipment and modifications to existing equipment that would enable the Refinery to process heavy gas oil (HGO), which is a by-product that is currently produced onsite and exported. Implementation of the CFEP would allow overall Refinery production to increase by up to 1,000,000 gallons per day (30 percent over current levels).

The CFEP includes the following: (1) construction of a new Hydrogen Plant to be built by Air Liquide with a capacity of 120 million standard cubic feet per day; (2) construction of a new Sulfur Recovery Unit with a capacity increase of 200 long tons per day; (3) conversion of a retired lube oil rail car loading rack into a butane rail car loading rack; (4) expansion of the Unicracker to allow for HGO hydrocracking and resulting in an increase in capacity of 23,000 barrels per day (bbl/day); (5) Reformer (Unit 244) modifications resulting in a capacity increase from 16,087 bbl/day to 18,500 bbl/day; (6) UNISAR (Unit 248) modifications resulting in a capacity increase from 8,812 bbl/day to 16,740 bbl/day; (7) Product Blending Unit (Unit 76) modifications resulting in a capacity increase from 90,411 bbl/day to 113,150 bbl/day; (8) Deisobutanizer (Unit 215 DIB) modifications resulting in a capacity increase from 7,600 bbl/day to 10,200 bbl/day; (9) Sulfur Recovery Plant (Units 234, 236, 238) modifications that would include a new sulfur degassing system, a new sulfur loading rack, a modified or replaced amine regenerator and an increase in sulfur storage capacity; and (10) modifications to ancillary facilities such as pumps, heat exchangers, instrumentation, utilities and piping.

Contra Costa County Community Development Department (CDD) acted as Lead Agency under the California Environmental Quality Act (CEQA) for this project. As a responsible agency under CEQA, the Bay Area Air Quality Management District (BAAQMD) participated in the EIR process, including reviewing and commenting on the Draft EIR. The following timeline illustrates the land use permit application’s progress from approval by County Planning Commission (CPC) to present:

- April 24, 2007 – Public hearing held before the CDD in Martinez to consider certification of the Final EIR and approval of the CFEP.

- May 8, 2007 – Second CPC hearing held in Martinez. Final EIR was certified and project was approved with new and modified Conditions of Approval.

- May 17, 2007 – Appeal received from Communities for a Better Environment and Center for Biological Diversity (CBE/CBD), joint appellants.

- May 18, 2007 – Appeal received from ConocoPhillips Company and appeal received from the California State Attorney General.

- September 10, 2007 – California Attorney General withdrew his May 18, 2007 appeal and submits a copy of Settlement Agreement with ConocoPhillips Company. Concurrently, ConocoPhillips requests that the County include language from the Settlement Agreement in the County's action on its appeal.

- September 25, 2007 – Board of Supervisors hearing held in Martinez. Final EIR was certified and project was approved. Board accepted the September 10, 2007 letter from the California Attorney General withdrawing their May 18, 2007 appeal. The Board denied the appeals of Communities for a Better Environment (CBE) and Center for Biological Diversity (CBD). The Board also granted the appeal of ConocoPhillips Company based on their revised proposed condition of approval addressing the storage of rail cars.

The EIR identified certain potentially significant environmental impacts that could occur as a result of the CFEP. The following discussion summarizes the air quality related effects identified in the EIR and during the District's review of the ConocoPhillips and Air Liquide permit applications, makes one or more of the findings required under Section 15091 of the State CEQA Guidelines, and presents facts to support the findings. All of these effects have been mitigated to a level of insignificance.

Impact 1 – Construction activities associated with CFEP would generate short-term emissions of criteria pollutants, including suspended and respirable particulate matter and equipment exhaust emissions, which would contribute to existing air quality violations.

Mitigated to insignificance. Particulate emissions will be mitigated by implementation of comprehensive dust control measures including watering all active construction areas at least twice daily; covering of haul trucks or requiring all trucks to maintain at least two feet of freeboard; paving or otherwise stabilizing haul roads, parking and staging areas; and sweeping daily with water sweepers all paved access roads, parking areas and staging areas at construction sites. The following "enhanced" control measures will also be implemented: Hydroseeding or application of non-toxic soil stabilizers to inactive construction areas; enclosing, covering, watering twice daily or application of non-toxic soil binders to exposed stockpiles; installation of sandbags or other erosion control measures to prevent silt runoff to public roadways; suspension of excavation and grading activity when winds exceed 25 mph; installation of wheel washers for all exiting trucks, or washing off the tires or tracks of all trucks and equipment leaving the site.

Equipment emissions will be mitigated by regular equipment maintenance and limits to unnecessary idling. Other equipment mitigation measures include the following: use of alternative fuels and/or alternatively fueled equipment; use of post-1996 model diesel trucks only at the site or for on-road hauling of construction material; requirement for all construction diesel engines with a rating of 100 hp or more to meet at a minimum the Tier 2 California Emission Standards for Off-Road Compression –Ignition Engines unless certified by the onsite Construction Air Quality Mitigation Manager (CAQMM) that such an engine is not available for a particular item of equipment; offering incentives to encourage construction workers to carpool or employ other means of transportation; scheduling construction activities to allow at least 33% of the construction workforce to avoid the morning and afternoon peak traffic periods; and use of on-site power to minimize reliance on portable generators.

Impact 2 – Operational activities associated with the implementation of the CFEP would increase air pollutant emissions, contributing to existing air quality violations.

Mitigated to insignificance. As required by BAAQMD Rules and Regulations, project emissions will be mitigated by application of Best Available Control Technology (BACT) and by obtaining emission offsets. Specifically, following mitigation measures will be implemented:

- The four Dissolved Air Flotation (DAF) vents associated with the onsite wastewater treatment plant will be routed to a Thermal Oxidizer with a destruction efficiency of no less than 98 percent. The DAF outlet channel and downstream sumps will be sealed by a solid cover with gaskets. Any vents installed on the covered channel will be routed to the thermal oxidizer. Installation of these controls will reduce organic emissions by at least 242 pounds per day and 44.1 tons per year.

- The Refinery Steam Power Plant uses three gas turbines to generate electricity, and uses gas turbine waste heat to generate steam. Each gas turbine has a nitrogen oxide (NOx) catalyst system located at the base of the exhaust stack. The Refinery will take a new permit limit to achieve a reduction of NOx concentration in each stack by 1 ppm from its current operating baseline. This 1 ppm of NOx equates to a reduction of 81 pounds per day and 14.7 tons per year.

- Operations at the ConocoPhillips' Carbon Plant will be modified to result in a decrease in SO2 emissions of at least 230 pounds per day and 42 tons per year. The refinery will take a new permit limit to reflect this reduction.

- The baghouse at the Carbon Plant will use improved bag technology to capture particulate matter (PM_{10}) from the calcined coke operation. Installation of the improved bag-technology will reduce PM_{10} emissions by at least 43.8 pounds per day and 8.0 tons per year. The refinery will take a new permit limit to reflect this reduction.

- Net reductions in ROG emissions associated with the mitigated CFEP will be used to offset 36 pounds per day and 7.6 tons per year of NOx associated with the CFEP.

Impact 3 – The CFEP would contribute to cumulative regional air emissions; however, it would not be cumulatively considerable and it would not conflict with or obstruct implementation of the applicable air quality plan.

Mitigated to insignificance. As discussed in Impact 2, with the proposed mitigation measures, the CFEP would have a less-than-significant impact on air quality. Furthermore, as discussed in Section 4.10, Land Use, in Final EIR, the CFEP is consistent with the Contra Costa County General Plan which in turn is consistent with the BAAQMD's current air quality plan (2005 Ozone Strategy).

Impact 4 – Operational activities associated with the implementation of the CFEP could lead to increases in odorous emissions. This would be a less-than-significant impact.

No mitigation required. The CFEP will not result in increased odors because the hydrocracking process that would be used to process heavy gas oil produces clean intermediate feedstocks and blendstocks. Storing these products in existing tanks will not increase odors. Also, CFEP contains numerous design features that will reduce odor emissions from existing equipment and minimize the likelihood of odor emissions from the project's new equipment. CFEP-related design features include the following:

- A fourth compressor will be added to the odor abatement system. This will increase the robustness of the odor control system. The new compressor will be sized at approximately 3.3 MMSCFD and is slated to commence operation in March 2009.

- The new compressor will primarily be loaded with odor abatement gases but will be operated so that during most periods, it can pick up the swings that occur during brief peak loading on the existing G-503, Flare Gas Recovery (FGR) compressor. This new compressor will also be used to mitigate flaring when the G-503 FGR compressor is down for planned or emergency maintenance. This additional flare gas recovery capacity will further reduce odor-causing flaring.

- The vapor recovery will be installed on existing fixed-roof tanks that will change service to store heavy gas oil and sour water.

- The Odor abatement system will be subject to new and more stringent permit conditions by the BAAQMD to eliminate and/or minimize odor complaints.

- A new sulfur recovery unit will increase system redundancy and improve the refinery's ability to react to upset conditions for processing sulfur gases. This will reduce the number of refinery upsets and shutdowns.

- Molten sulfur loaded into trucks will be degassed prior to loading, which will reduce the H_2S emissions.

- The Dissolved Air Flotation unit at the wastewater treatment plant will be vented to a thermal oxidizer.

- After startup of the CFEP, less heavy gas oil will be loaded onto barges, which vent to the atmosphere.

As required by the State CEQA Guidelines, the BAAQMD, as a Responsible Agency for the ConocoPhillips CFEP, hereby finds that, for each of the impacts identified in the final EIR and discussed above, changes or alterations have been required in, or incorporated into, the project which avoid or substantially lessen the significant environmental effect as identified in the final EIR. In addition, for those mitigation measures that are identified in the final EIR to lessen impacts associated with construction activities and vehicle emissions and that are within the responsibility or jurisdiction of another public agency, the BAAQMD hereby finds that such measures either have been or can and should be adopted by such other agency.

In accordance with BAAQMD Rules and Regulations, the BAAQMD has fully considered the EIR prepared and certified by the Contra Costa County and has incorporated the EIR's analysis into its decision-making process. The BAAQMD granted an Authority to Construct for the proposed project on October 5, 2007.

The documents and other materials that constitute the record of proceedings upon which this decisions is based are located at the BAAQMD office at 939 Ellis Street, San Francisco, California, and the custodian of the materials is Rochelle Henderson.

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Jack P. Broadbent
Executive Officer/Air Pollution Control Officer
Bay Area Air Quality Management District

APPENDIX D

Engineering Evaluation Application 13678

FINAL

ENGINEERING EVALUATION
Air Liquide Large Industries, U.S. LP; Facility B7419
APPLICATION NO. 13678

October 5, 2007

Table of Contents

1. BACKGROUND

Air Liquide has submitted an application to build a hydrogen plant at the ConocoPhillips refinery in Rodeo. This is part of ConocoPhillips "Clean Fuel Expansion Project (CFEP)." The purpose of the project is to process heavy gas oil that ConocoPhillips produces at the coker crude unit, coker, and pre-fractionator into gasoline and diesel fuel.

ConocoPhillips needs more hydrogen than it can currently produce to process the heavy gas oil. Air Liquide will build a new hydrogen plant on site and will retain ownership of the plant and operate it. However, ConocoPhillips will use all of the facility's output. BAAQMD Regulation 2-1-213 defines facility as:

> "Any property, building, structure or installation (or any aggregation of facilities) located on one or more contiguous or adjacent properties and under common ownership or control of the same person…"

The hydrogen plant will be on ConocoPhillips property, so it meets the conditions of "contiguous or adjacent." In addition, the hydrogen plant will take its feed from the refinery. ConocoPhillips will direct the hydrogen plant to produce the amount of hydrogen that it needs at any time, so the hydrogen plant is considered to be under Conoco's control. Therefore, the hydrogen plant will be considered to be part of the refinery.

Since it is part of the refinery, the two projects (CFEP and hydrogen plant) will be considered as one project for the purposes of NSR, PSD, Major Facility Review (Title V), offsets, NSPS, NESHAPS, and any other applicable requirements.

The Title V regulations in 40 CFR 70 allow agencies to issue more than one Title V permit to a facility. Because the hydrogen plant will be owned and operated by Air Liquide, it will have a separate plant number, B7419, and a separate application, No. 13678.

The ConocoPhillips Carbon Plant, Plant A0022, is owned and operated by ConocoPhillips. It is contiguous to the refinery. Although it has a separate plant number and Title V permit, it is also considered part of the facility. The applicant will reduce emissions at the carbon plant to obtain reductions in actual emissions of PM10 for the purposes of CEQA and contemporaneous offsets of SO2.

The list of equipment at the proposed Air Liquide plant is shown below:

- S1, Hydrogen Plant, 120 MMscf/day, including HRSG and steam turbine generator (12 MW)
- S2, Hydrogen Plant Furnace, 1,072 MMbtu/hr abated by A1, SCR
- S3, Hydrogen Plant Flare, 2200 MMbtu/hr
- S4, Cooling Tower, 3,700 gpm
- S5, Ammonia Tank, 10,000 gal-19% aqueous ammonia
- A1, Selective Catalytic Reduction Unit abating S2, Hydrogen Plant Furnace

S4, Cooling Tower, is exempt from permits because BAAQMD Regulation 2-1-128.4 exempts water cooling towers provided that the source does not require permitting pursuant to BAAQMD Regulation 2-1-319. This section would require permits if the source emits more than 5 tons per year of any regulated air pollutant. Some large cooling towers emit enough POC or PM10 to require permits. This cooling tower will have permit conditions requiring monitoring to ensure that the emissions of POC and PM10 each do not exceed the amounts stated in the application.

S5, Ammonia Tank, is exempt from permits because BAAQMD Regulation 2-1-113.2 exempts vessels used exclusively for the storage of any aqueous solution containing less than 1% organic compounds by weight provided that the source does not require permitting pursuant to BAAQMD Regulation 2-1-319. This section would require permits if the source emits more than more than 5 tons per year of any regulated air pollutant or the source emits more than the trigger level for any toxic air contaminant. The tank is a pressure tank and is unlikely to emit more than the trigger level of ammonia (7,700 lb) in any year.

Air Liquide will use the excess heat generated at the hydrogen plant to make steam and will provide steam to ConocoPhillips. This will enable ConocoPhillips to shut down an older 256 MMbtu/hr boiler, S8. Air Liquide will also use steam to power a steam turbine to generate electricity for its own use and for ConocoPhillips. A maximum of 12 MW will be generated; the new hydrogen plant will use 4.5 MW. ConocoPhillips will use the remainder.

2. EMISSIONS

Following is a summary of the original proposed emissions of NOx, SO2, PM10, POC, and CO in tons per year from the proposed Air Liquide hydrogen plant. The annual emissions were calculated for the average operating rate of 975 MMbtu/hr. The maximum daily emissions were calculated for the maximum operating rate of 1,072 MMbtu/hr.

Summary of Hydrogen Plant Emissions

	Tons per Year					
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**	
New SMR Furnace	28.1	5.0	15.8	11.5	34.2	(975 MMBtu/hr, annual average)
Deaerator Vent	--	--	--	0.8	--	
Flare Pilots/NG Purge	0.12	0.004	--	--	1.1	
Startup/Shutdown	2.7	0	0	0.1	11	
Cooling Tower			0.5	1.5		
Fugitives	--	--	--	1.5	--	
Total	30.9	5.0	16.3	15.4	46.2	

	Lb per Day					
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**	
New SMR Furnace	169	30	95	69	206	(1072 MMBtu/hr, hourly maximum)
Deaerator Vent	--	--	--	4.4	--	
Flare Pilots/NG Purge	0.68	0.022	--	--	5.9	
Cooling Tower			2.5	8		
Fugitives	--	--	--	8.2	--	
Total	170	30	97.5	89.9	212	

Air Liquide's final proposal is to reduce the particulate emissions from the new SMR furnace to 13.8 tons per year. Air Liquide may comply by showing that the particulate emission factor is less than 0.0037 lb/MMbtu or by curtailing operations. The resulting annual emissions are:

Summary of Hydrogen Plant Annual Emissions

	Tons per Year				
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**
New SMR Furnace	28.1	5.0	13.8	11.5	34.2
Deaerator Vent	--	--	--	0.8	--
Flare Pilots/NG Purge	0.12	0.004	--	--	1.1
Startup/Shutdown	2.7	0	0	0.1	11
Cooling Tower			0.5	1.5	
Fugitives	--	--	--	1.5	--
Total	30.9	5.0	14.3	15.4	46.2

Air Liquide has calculated the maximum daily emissions for the flare. If the pressure swing absorption process malfunctions, up to 7.74 MMscf/hr of syngas could be sent to the flare for 5.3 hours/event. The composition of syngas is mainly hydrogen, methane, and CO, as shown below: (This paragraph has been amended to be consistent with the flare emission calculations in Appendix A.)

Component	% by Weight	% by Volume
Hydrogen	13.4	73
Nitrogen	0.2	<0.09
Carbon Dioxide	68.5	17
Carbon Monoxide	10.3	4
Methane	7.3	5
Ethane	<0.001	<0.0001
Water	0.3	0.2

In this case, approximately 686 lb NOx/day would be emitted and 3,537 lb CO/day would be emitted. In this case, the hydrogen plant and hydrogen plant furnace would shut down, so normal emissions would not be emitted concurrently with the flare emissions.

	Lb per Highest Day				
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**
Flare	686	0	negligible	0	3,537

The detailed calculations of the flare emissions are in Appendix A.

Following is the detail of the emissions of toxic air contaminants on which the health risk screening analysis was based. These emissions were based on a heat input rate of 1,100 MMbtu/hr to S2, Hydrogen Plant Furnace. The average hourly rate has been reduced to 975 MMbtu/hr, so the typical emissions will be lower. Also the proposed emissions of methanol have been reduced to 0.61 lb/day or 223 lb/yr. Emission factors from WSPA/API's Air Toxic Emission Factors for Combustion Sources Using Petroleum-Based Fuels, final report, Volume 2, Appendix B, April 14, 1998 have been used for the calculations of all emissions from the heater except ammonia and sulfuric acid mist. The ammonia calculations are based on the "ammonia slip", the ammonia that is lost when injected into A1, SCR, for NOx control. The sulfuric acid mist is based on the assumption that the ratio of SO2 to SO3 in combustion is 20:1, and that all SO3 becomes sulfuric acid mist. The detailed calculations are in Appendix B of the engineering evaluation for Application 13424.

Substance	Emissions (lb/yr)						
	S2, Hydrogen Plant Furnace	**Flare Pilots**	**Deaerator Vent**	**Cooling Tower[a]**	**Hydrogen Plant Fugitives**	**Total Annual Emissions (lb/yr)**	**BAAQMD Trigger Level (lb/yr)**
Acenaphthene	2.27E-02					2.27E-02	
Acenaphthylene	1.49E-02					1.49E-02	
Acetaldehyde	1.47E+02	2.02E-01				**1.48E+02**	6.40E+01
Acrolein		4.69E-02				4.69E-02	2.30E+00
Ammonia	4.82E+04		5.59E+03		0.00E+00	**5.38E+04**	7.70E+03
Antimony	4.98E+00					4.98E+00	7.70E+00
Arsenic	8.19E+00					**8.19E+00**	1.20E-02
Benzene	6.23E+02	7.46E-01				**6.24E+02**	6.40E+00
Benzo(a)anthracene	3.09E-01					3.09E-01	0.011[b]
Benzo(a)pyrene	8.63E-01					8.63E-01	0.011[b]
Benzo(b)fluoranthene	3.89E-01					3.89E-01	0.011[b]
Benzo(k)fluoranthene	2.32E-01					2.32E-01	0.011[b]

Substance	Emissions (lb/yr)						
	S2, Hydrogen Plant Furnace	**Flare Pilots**	**Deaerator Vent**	**Cooling Tower[a]**	**Hydrogen Plant Fugitives**	**Total Annual Emissions (lb/yr)**	**BAAQMD Trigger Level (lb/yr)**
1,3-Butadiene					4.84	**4.84E+00**	1.10E+00
Cadmium	9.52E+00					**9.52E+00**	4.50E-02
Chlorine				3.95E-02		3.95E-02	7.70E+00
Chloroform				9.94E+00		9.94E+00	3.40E+01
Chromium (Total)	1.03E+01					**1.03E+01**	1.30E-03
Chrysene	1.57E-02					1.57E-02	
Copper	4.06E+01					4.06E+01	9.30E+01
Ethylbenzene	2.91E+02	6.78E+00				2.98E+02	7.70E+04
Fluoranthene	2.95E-02					2.95E-02	
Fluorene	1.04E-01					1.04E-01	
Formaldehyde	1.07E+03	5.48E+00				**1.08E+03**	3.00E+01
n-Hexane		1.36E-01			7.50E+00	7.63E+00	2.70E+05
Indeno(1,2,3-cd)pyrene	9.93E-01					9.93E-01	0.011*
Lead	4.71E+01					**4.71E+01**	5.40E+00
Manganese	6.56E+01					**6.56E+01**	7.70E+00
Mercury	1.73E+00					**1.73E+00**	5.60E-01
Methanol			~~1.75E+04~~ 2.23+02			1.75E+04	1.50E+05
Naphthalene	3.02E+00	6.57E-02				3.08E+00	5.30E+00
Nickel	9.08E+01					**9.08E+01**	7.30E-01
Phenanthrene	1.41E-01					1.41E-01	
Phenol	5.43E+01					5.43E+01	7.70E+03
Propylene	2.09E+01	1.14E+01				3.24E+01	1.20E+05
Pyrene	2.39E-02					2.39E-02	

Substance	**Emissions (lb/yr)**						
	S2, Hydrogen Plant Furnace	**Flare Pilots**	**Deaerator Vent**	**Cooling Tower**[a]	**Hydrogen Plant Fugitives**	**Total Annual Emissions (lb/yr)**	**BAAQMD Trigger Level (lb/yr)**
Selenium	1.89E-01					1.89E-01	7.70E+02
Silver	1.55E+01					1.55E+01	
Sulfuric Acid Mist	8.6E+02					8.6E+02	3.9E+01
Toluene	1.03E+03	2.72E-01				1.03E+03	1.20E+04
1,2,4-Trimethylbenzene							
Xylene (Total)	3.59E+02	1.36E-01				3.60E+02	2.70E+04
Zinc	2.00E+02					2.00E+02	1.40E+03

[a] Chloroform emissions from the cooling tower were calculated using an emission factor of 0.0034 lb $CHCL_3$ per lb of Cl_2 used to chlorinate the cooling waters. Emission factor is from *Proposed Identification of Chloroform as a Toxic Air Contaminant* (CARB, September 1990. http://www.arb.ca.gov/toxics/summary/chloroform_A.pdf). Cl_2 usage based on bleach density of 10 lb/gal, 12,5 wt% NaOCL (avg. of 9-16% bleach solution), 0.3 lb Cl_2/gal.

[b]These substances are PAH derivatives that have OEHHA-developed Potency Equivalency Factors. These PAHs should be evaluated as benzo(a)pyrene equivalents. This evaluation process consists of multiplying individual PAH-specific emission levels with their Potency Equivalency Factor, which is 0.1. The sum of these products is the benzo(a)pyrene equivalent level and should be compared to the benzo(a)pyrene equivalent trigger level.

This table shows the average hourly emissions of toxic air contaminants:

Substance	Emissions (lb/hr)						
	SMR Furnace	Flare Pilots	Deaerator Vent	Cooling Tower	Hydrogen Plant Fugitives	Total Hourly Emissions (lb/hr)	BAAQMD Trigger Level (lb/hr)
Acenaphthene	3.07E-06					3.07E-06	
Acenaphthylene	2.02E-06					2.02E-06	
Acetaldehyde	1.99E-02	2.30E-05				1.99E-02	
Acrolein		5.36E-06				5.36E-06	4.20E-04
Ammonia	6.50E+00		6.40E-01		0.00E+00	7.14E+00	7.10E+00
Antimony	6.72E-04					6.72E-04	
Arsenic	1.11E-03					**1.11E-03**	4.20E-04
Benzene	8.41E-02	8.52E-05				8.42E-02	2.90E+00
Benzo(a)anthracene	4.17E-05					4.17E-05	
Benzo(a)pyrene	1.16E-04					1.16E-04	
Benzo(b)fluoranthene	5.25E-05					5.25E-05	
Benzo(k)fluoranthene	3.13E-05					3.13E-05	
1,3-Butadiene					5.53E-04	5.53E-04	
Cadmium	1.28E-03					1.28E-03	
Chorine				4.50E-06		4.50E-06	4.60E-01
Chloroform				1.13E-03		1.13E-03	3.30E-01
Chromium (Total)	1.39E-03					1.39E-03	
Chrysene	2.12E-06					2.12E-06	
Copper	5.47E-03					5.47E-03	2.20E-01
Ethylbenzene	3.93E-02	7.73E-04				4.00E-02	
Fluoranthene	3.98E-06					3.98E-06	

Substance	Emissions (lb/hr)						
	SMR Furnace	Flare Pilots	Deaerator Vent	Cooling Tower	Hydrogen Plant Fugitives	Total Hourly Emissions (lb/hr)	BAAQMD Trigger Level (lb/hr)
Fluorene	1.40E-05					1.40E-05	
Formaldehyde	1.44E-01	6.26E-04				1.45E-01	2.10E-01
n-Hexane		1.55E-05			8.56E-04	8.72E-04	
Indeno(1,2,3-cd)pyrene	1.34E-04					1.34E-04	
Lead	6.36E-03					6.36E-03	
Manganese	8.85E-03					8.85E-03	
Mercury	2.34E-04					2.34E-04	4.00E-03
Methanol			2.55-02			2.00E+00	6.20E+01
Naphthalene	4.07E-04	7.50E-06				4.14E-04	
Nickel	1.22E-02					1.22E-02	1.30E-02
Phenanthrene	1.90E-05					1.90E-05	
Phenol	7.32E-03					7.32E-03	1.30E+01
Propylene	2.82E-03	1.31E-03				4.13E-03	
Pyrene	3.22E-06					3.22E-06	
Selenium	2.55E-05					2.55E-05	
Silver	2.09E-03					2.09E-03	
Sulfuric Acid Mist	9.8E-02					9.8E-02	2.6E-01
Toluene	1.39E-01	3.11E-05				1.39E-01	8.20E+01
1,2,4-Trimethylbenzene							
Xylene (Total)	4.85E-02	1.55E-05				4.85E-02	4.90E+01
Zinc	2.70E-02					2.70E-02	

The detailed emission calculations for each source are in Attachment A.

The summary of the emissions for the whole project, which includes Applications No. 13424 for Facility A0016, ConocoPhillips, No. 13678 for Air Liquide, and No. 15328 for contemporaneous offsets from Facility A0022, ConocoPhillips Carbon Plant, are contained in Application No. 13424. The discussion of emissions for the purposes of PSD applicability, CEQA, offsets, and BACT are also contained in Application No. 13424.

3. Best available Control Technology (BACT)

Following are the maximum daily emissions for the various sources:

	Lb per Highest Day				
Source	**NOx**	**SO2**	**PM10**	**POC**	**CO**
New SMR Furnace	169	30	95	69	206
Hydrogen Plant	--	--	--	12.6	--
Hydrogen Plant Flare	686				3,537
Cooling Tower			2.5	8	

S1, Hydrogen Plant, is subject to BACT because it will emit more than 10 lb/highest day of POC.

S2, Hydrogen Plant Furnace, is subject to BACT because it will emit more than 10 lb/highest day of these pollutants: NOx, SO2, POC, CO, and PM10.

S3, Hydrogen Plant Flare, is subject to BACT because it will emit more than 10 lb/highest day of these pollutants: NOx and CO.

The following source is not subject to BACT because it will not emit more than 10 lb/day of NOx, SO2, POC, CO, or PM10:
S5, Ammonia Tank

The following source is not subject to BACT because it is exempt from permitting in accordance with BAAQMD Regulation 2-1-128.4.
S4, Cooling Tower
If the source emits more than 5 tons per year of any regulated air pollutant, it would still be subject to permitting in spite of the exemption.

The applicant estimates that emissions of POC from S4 will be less than 8.0 lb/day (1.5 tpy) and the emissions of PM10 will be less than 2.5 lb/day. POC levels in cooling towers can spike, however, if there is a leak in a heat exchanger. The permit will contain monitoring conditions to ensure that the POC emissions remain under 5 tons per year. It is far less likely that PM10 emission will be over 5 tons per year, especially with limits on dissolved solids content of the water.

S5, Ammonia Tank, will not have emissions of NOx, SO2, POC, CO, or PM10 and therefore is not subject to BACT.

<u>S1, Hydrogen Plant</u>

The components (valves, flanges, pumps, compressors, etc.) at the hydrogen plant and the deaerator vent are subject to BACT because they are estimated to emit more than 10 lb POC/highest day. BACT for petroleum refinery fugitive emissions in accordance with the Section 3 of the District's BACT handbook is:

- Graphitic gaskets for flanges
- Live loaded packing systems and polished stems, or equivalent, for valves
- "Wet" dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas for hydrocarbon centrifugal compressors
- Seal-less design or dual mechanical seals with a heavy liquid barrier fluid, or equivalent, for pumps
- Fugitive equipment monitoring and repair program for all components

BACT for the deaerator vent at hydrogen plants has not been hitherto defined. Air Liquide has proposed emissions of 4.35 lb POC/day at the vent. No other hydrogen plants in the Bay Area have mass emission limits on the deaerator vents. Source tests of the vents have shown much higher emissions. No BACT determinations or limits for deaerator vents were found in the EPA, ARB, or SCAQMD BACT Clearinghouses. SCAQMD does have Rule 1189 with a limit of 0.5 lb VOC/MMscf of H2 produced. This would be equivalent to 60 lb POC/day at the vent.

An emission rate of 4.35 lb/hr will be considered to be BACT for this source.

<u>S2, Hydrogen Plant Furnace</u>
Air Liquide has proposed the following BACT levels for S2, Hydrogen Plant Furnace:

Pollutant	Concentration		Emission Factor, lb/MMbtu	Reference for BACT
NOx	5	ppmvd @ 3% O_2	0.00658	*SCAQMD BACT
SO_2	35	ppmv total S in RFG/NG	0.0012	BAAQMD BACT (PSA/fuel gas Mix)
PM10	3.8	lb/MMcf (natural gas)	0.0037	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H2 in fuel)
POC	2.75	lb/MMcf (natural gas)	0.0027	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H2 in fuel)
CO	10	ppmvd @ 3% O_2	0.0080	SCAQMD BACT

*South Coast Air Quality Management District

These levels are lower than the levels in the District BACT/TBACT handbook. Air Liquide is relying on a top-down analysis of BACT for NOx and PM10 at the hydrogen plant that was performed by ConocoPhillips for Application 13424. This analysis is required as part of the PSD analysis. This analysis is attached in Appendix B. The furnace is compared to various recent hydrogen plant furnaces. These furnaces burn primarily pressure swing absorption gas (PSA gas), which results in lower emissions of NOx and CO than natural gas and refinery fuel gas (RFG). The applicant estimates that this furnace will burn approximately 85% PSA gas and 15% RFG/natural gas.

There are 4 BACT determinations by the SCAQMD for hydrogen plant furnaces with levels for NOx of 5 ppmdv @ 3% O2. This is the lowest NO_x emission limit achieved in practice. BACT will be achieved by using SCR and by burning mostly PSA gas.

For particulate matter, the conclusion drawn by the top-down analysis was that only good combustion practice is considered to be BACT for controlling PM10 from gas-fired heaters. The level proposed by the applicant is equivalent to 0.0025 gr/dscf (assuming that the F-factor is the same as the F-factor for natural gas). This is lower than the 0.01 proposed for a 2,088 MMbtu/hr natural gas fired boiler proposed in SCAQMD BACT determination #427061 in 2006.

Also, SCAQMD BACT determination #411357 established that 0.0065 lb PM10/MMbtu was BACT (based on a limit of 3642 lb/mo, 780 MMbtu/hr, an assumption of 720 hr/mo. operation). Air Liquide has proposed 0.0037 lb PM10/MMbtu for this application.

For SO2, the level proposed compares favorably with the 40 ppm S in fuel as H2S in SCAQMD BACT determination #411357 for a 780 MMbtu/hr steam reformer furnace with similar fuels, and very favorably with the 0.2 lb/MMbtu level in SCAQMD BACT determination #427061 for a 2,088 MMbtu/hr natural gas-fired boiler.

The proposed CO concentration of 10 ppm@ 3% O2 is equivalent to the last SCAQMD BACT determination #411357.

For POC, SCAQMD BACT determination #411357 determined that 0.0061 lb POC/MMbtu was BACT (based on a limit of 3399 lb/mo, 780 MMbtu/hr, an assumption of 720 hr/mo operation). Air Liquide has proposed 0.0027 lb POC/MMbtu for this application.

The District concludes that the levels proposed for S2, Hydrogen Plant Furnace, represent BACT.

Air Liquide is relying on a top-down analysis of BACT for NOx and PM10 at the hydrogen plant furnace that was performed by ConocoPhillips for Application 13424. This analysis is required as part of the PSD analysis. The analysis is attached in Appendix B.

Air Liquide has also proposed a maximum emission rate during start-up, shutdown, and malfunction of 50 lb NOx/clock hour.

<u>S3, Hydrogen Plant Flare</u>
The main purpose of the flare is to dispose of hydrogen and CO in an emergency for safety reasons. Hydrogen is not a pollutant.

The flare's emissions on the highest day may be up to 686 lb NOx/day and 3,537 lb CO/day, as shown in the flare calculations in Appendix A. However, the flare will only be used occasionally when there is a shutdown, malfunction, during maintenance, or when there is a sudden drop in the refinery's use of hydrogen. The total annual emissions from the flare are estimated at 2.7 tpy NOx and 11 tpy CO. There are also small ongoing emissions from the flare pilots, which ensure that a flame is present at all times. Because the emissions of NOx and CO will be more than 10 lb/day on the highest day, the flares are subject to BACT.

The District's BACT/TBACT Workbook states that an enclosed ground level flare with a control efficiency of 98.5% for POC is BACT1. BACT1 for CO is undetermined at this point.

The applicant has stated that the flare is not subject to BACT for POC because the gases sent to the flare do not contain more than 10 lb POC/day. Following is the gas composition:

Component	% by Weight	% by Volume
Hydrogen	13.4	73
Nitrogen	0.2	<0.09
Carbon Dioxide	68.5	17
Carbon Monoxide	10.3	4
Methane	7.3	5
Ethane	<0.001	<0.0001
Water	0.3	0.2

Because none on the components is considered to be POC, the flare is not subject to BACT for POC.

As shown in the flare calculations, the flare is a control device for CO and a generator of NOx. The calculations assume 98% control of CO.

Testing is not feasible for elevated flares because they are open and have no stack. If the flare were enclosed, it might be possible to test for destruction efficiency. It is likely that if the flare were enclosed, NOx emissions would rise and CO emissions would drop due to increased residence time. It is not sensible to specify an enclosed ground level flare simply to enable testing. Moreover, enclosed ground level flares are generally small. For example, the largest enclosed ground level flare at a landfill in the District, where these flares are commonly used, has a capacity of 120 MMbtu/hr.

Due to the capacity of this flare (2,220 MMbtu/hr), District staff concluded that a ground-level enclosed flare was not feasible in this case. The facility will install an elevated flare. These flares are considered to have a control efficiency of 98% for CO.

4. CUMULATIVE INCREASE AND OFFSETS

The cumulative increase for the facility is shown below.

	Tons per Year				
	NOx	**SO2**	**PM10**	**POC**	**CO**
Total	30.9	5.0	13.8*	13.9*	46.2

*The emissions from the exempt cooling tower at the hydrogen plant are not considered to be part of the cumulative increase and are not subject to offsets.

BAAQMD Regulation 2-2-302 requires offsets for NOx and POC because the emissions of the facility, which includes the ConocoPhillips refinery (Facility

A0016) and the ConocoPhillips carbon plant (Facility A0022), will be greater than 35 tons per year. The refinery emitted approximately 335 tons NOx and 283 tons POC and the carbon plant emitted approximately 532 tons NOx in 2005 according to District estimates.

In accordance with BAAQMD Regulation 2-2-302.2, POC credits shall be used to offset part of the NOx increases.

BAAQMD Regulation 2-2-303 requires offsets for SO2 and PM10 at major facilities. ConocoPhillips is a major facility for PM10 because the refinery emitted approximately 126 tons PM10 and the carbon plant emitted approximately 63 tons PM10 in 2005 according to District estimates. It is a major facility for SO2 because the refinery emitted approximately 424 tons SO2 and the carbon plant emitted approximately 1212 tons SO2 in 2005 according to District estimates.

The discussion of offsets required and provided for this project can be found in the engineering evaluation for Application 13424.

The PM10 offsets will come from the following certificates:

Certificate Number	Owner of Record	Amount tpy
920	ConocoPhilips	6.650
979	Air Liquide	18.600
1032	Air Liquide	4.200
Total		29.45

5. STATEMENT OF COMPLIANCE

BAAQMD Regulation 1, General Provisions

The District requires NOx CEMs from sources that use SCR for control, therefore S2, Hydrogen Plant Furnace, is subject to 1-521 and 1-522. The source will also be required to have a CO CEM.

S2, Hydrogen Plant Furnace, will be subject to flow and ammonia injection monitoring and therefore will be subject to the parametric monitoring requirements in Section 1-523.

BAAQMD Regulation 2, Rule 1, General Requirements

S4, Cooling Tower, is exempt from permits because BAAQMD Regulation 2-1-128.4 exempts water cooling towers provided that the source does not require permitting pursuant to BAAQMD Regulation 2-1-319. This section would require permits if the source emits more than more than 5 tons per year of any regulated air pollutant. Some cooling towers emit enough POC or PM10 to require permits. This cooling tower will have permit conditions requiring monitoring to ensure that the emissions of POC and PM10 each do not exceed the amounts stated in the application, which were 1.5 tons per year and 0.5 tons per year, respectively.

S5, Ammonia Tank, 10,000 gal, is not required to have a permit because the storage of aqueous solutions that contains less than one percent by weight organic compounds is exempt in accordance with Section 123.2. The tank will be a pressure vessel with a nitrogen blanket. It will store 19% aqueous ammonia. The ammonia concentration will be limited to 19% because storage of higher concentrations is subject to 40 CFR 68, Accidental Release.

BAAQMD Regulation 2, Rule 5, New Source Review Of Toxic Air Contaminants

In accordance with BAAQMD Regulation 2, Rule 5, health risk assessment analysis was prepared by the facility and reviewed by District Staff. The project risk, including Plant A0016, ConocoPhillips refinery, meets the requirements as follows:

- Project cancer risk is less than 10.0 in a million;
- Project chronic hazard index is less than 1.0; and
- Project acute hazard index is less than 1.0.

The cancer risk for S2, Hydrogen Plant Furnace, is greater than 1.0 in a million. Therefore, the source is subject to TBACT in accordance with Section 2-5-301 of the rule. TBACT is the use of extremely clean fuels. Approximately 85% of the fuel that will be burned in the Heater will be PSA gas, which is extremely clean and has very little sulfur.

Also, the risk assessment for S2 is conservative, because it was based on an average heat input rate of 1,100 MMbtu/hr, but the final average heat input rate will be 975 MMbtu/hr, which is 12.8% less.

The chronic health index for all sources is below 0.2.

BAAQMD Regulation 6, Particulate Matter and Visible Emissions

The following sources are the new sources of particulate matter in this application:

S2, Hydrogen Plant Furnace abated by A1, SCR
S3, Hydrogen Plant Flare, 2200 MMbtu/hr
S4, Cooling Tower, 3,700 gpm

S2, Hydrogen Plant Furnace, and A1, SCR, are subject to Sections 6-301, 6-305, and 6-310.3 of the regulation. Section 6-301 is a requirement that visible emissions may not exceed 1.0 Ringelmann for more than 3 min/hr. Section 6-305 is a requirement that a unit may not emit visible particles that fall outside of the facility's property. Section 6-310.3 is the grain-loading limit for heat transfer operations of 0.15 gr filterable particulate/dscf @ 6% O2. (The "gr" used in this section means "grains," which are equal to 1/7000 of a pound.) S2 burns gaseous fuels and is expected to comply with these requirements.

S3, Hydrogen Plant Flare, is subject to Sections 6-301, 6-305, and 6-310 of the regulation. Section 6-310 is the general grain-loading limit of 0.15 gr filterable particulate/dscf. S3 burns gases and is expected to comply with these requirements.

S4, Cooling Tower, is subject to Sections 6-301, 6-305, 6-310, and 6-311 of the regulation. The cooling tower is expected to comply with these requirements. Previous analysis for Application 10349 shows that, for cooling towers, the amount of particulate matter is so small and the airflow is so large that compliance with 6-301, 6-310, and 6-310 is assured.

Compliance with Section 6-311 is on a process weight basis. The flow rate of water for the cooling tower is 3,700 gal/min. This is equivalent to 1.85 million lb/hr. If the process weight is over 57,320 lb/hr, the limit is 40 lb filterable particulate/hr. The emission rate shown in the calculations in Appendix A is 0.1 lb/hr, therefore the source will comply with Section 6-311.

BAAQMD Regulation 7, Odorous Emissions

The purpose of Regulation 7 is the general control of odorous compounds. Most odorous pollutants are handled generally. A few are mentioned by name. One of these is ammonia.

S1 Hydrogen Plant, and S2, Hydrogen Plant Furnace, are sources of ammonia. Section 7-303 limits concentration of ammonia from Type A emission points to 5000 ppm. Ammonia is used at S2 in the SCR for abatement of NOx. The hydrogen plant will emit up to 10 ppm of ammonia from the deaerator vent. The heater will comply because it has a limit of 10 ppmv ammonia @ 3% oxygen, as will the hydrogen plant because the concentration at the vent is low. The concentration of ammonia in the stacks of both sources will be measured by source test after construction.

BAAQMD Regulation 8, Rule 2, Miscellaneous Operations

The deaerator vent at the Hydrogen Plant, S1, and the cooling tower, S4, will be subject to this rule. Section 301 has the following limit:

> "A person shall not discharge into the atmosphere from any miscellaneous operation an emission containing more than 6.8 kg. (15 lbs.) per day and containing a concentration of more than 300 PPM total carbon on a dry basis."

If the emissions at the deaerator meet 4.35 lb/day as stated by the applicant, the deaerator will comply easily. Annual source tests will be required to ensure compliance.

Cooling towers are exempt from this rule, in accordance with Section 8-2-114, if best modern practices are used. The District has determined "best modern practices" for cooling towers and has documented them in the engineering evaluation for ConocoPhillips' Application 10349 as follows:

> "… daily visual inspection, plus water sampling and analysis for indicators of hydrocarbon leaks once per shift, is the best modern practice."

S4, Cooling Tower, will not comply with best modern practices, and therefore is subject to Regulation 8, Rule 2. The engineering evaluation also determined that the margin of compliance for most refinery cooling towers is 1000:1. Therefore, the cooling tower will comply with Regulation 8, Rule 2.

BAAQMD Regulation 8, Rule 10, Process Vessel Depressurization

The Hydrogen Plant, S1, will be subject to this rule. Section 301 of the rule requires that the emissions during depressurizing be controlled by an abatement device or the fuel gas system until the vessel is as close to atmospheric pressure as possible, but at least until the partial pressure of organic compounds in that vessel is less than 4.6 psig.

Section 302 requires that no process vessel may be opened to the atmosphere unless the internal concentration of total organic compounds has been reduced prior to release to atmosphere to less than 10,000 parts per million (ppm), with the following exception. Vessels may be opened when the concentration of total organic compounds is 10,000 ppm or greater provided that the total number of such vessels opened with such concentration during any consecutive five year period does not exceed 10% of the total process vessel population, the organic compound emissions from the opening of these vessels does not exceed 15 pounds per day and the vessels are not opened on any day on which the APCO predicts an exceedance of a National Ambient Air Quality Standard for ozone or declares a Spare the Air Day.

S1 is expected to comply with these requirements.

BAAQMD Regulation 8, Rule 18, Equipment Leaks

The components-valves, flanges, pumps, compressors, pressure relief devices-are subject to this rule. The rule has total organic leak limits of 100 ppm for valves and flanges and 500 ppm for pumps, compressors, and pressure relief devices. This is a "work-practice" standard. The facility is obligated to test the components for leaks on a periodic basis and repair the leaks. A small percentage of non-repairable leaks are allowed until the next turnaround or five years, whichever is sooner.

The facility will have an inspection program for this regulation and is expected to comply with these standards.

BAAQMD Regulation 8, Rule 28, Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants

This regulation applies to pressure relief devices (PRDs) installed on refinery equipment. Section 8-28-302 applies to PRDs on new or modified equipment. It requires that these PRDs comply with all requirements of BAAQMD Regulation 2, Rule 2, including BACT. BACT1 at this time is a rupture disk with a vent to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. All new PRDs installed pursuant to this project are subject to this standard. The applicant has determined that the use of rupture disks is not feasible at the hydrogen plant because of the high number of pressure cycles and high temperatures. The hydrogen plant will be required to comply with BACT2, the requirement to vent to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%.

Permit conditions with the BACT requirement will be added to these units. The facility is expected to comply with this requirement.

BAAQMD Regulation 9, Rule 1, Sulfur Dioxide

S2, Hydrogen Plant Furnace, and S3, Hydrogen Plant Flare, are small sources of SO_2 emissions. These sources are not subject to the 300-ppm limit in Section 9-1-301 of the rule because the refinery complies with the exemption in Section 9-1-110. The exemption requires ground level monitoring and compliance with the ground level concentration limit.

BAAQMD Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

S2, Hydrogen Plant Furnace, is subject to the rule because it applies to new heat transfer operations with a maximum heat input greater than 250 MMbtu/hr, per

Section 9-3-303. The source will easily comply with the 125 ppm limit for gaseous fuels because it is designed to comply with the 5 ppm @ 3% O2 BACT limit.

BAAQMD Regulation 9, Rule 10, Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries

S2, Hydrogen Plant Furnace, is not subject to this regulation because it applies to affected units. Affected units are defined by Section 9-10-220 as "any petroleum refinery boiler, steam generator, or process heater… having an Authority to Construct or a Permit to Operate prior to January 5, 1994." This heater will be subject to current BACT limits for NOx and CO, which are more stringent, instead of the Regulation 9, Rule 10, limits.

BAAQMD Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries and BAAQMD Regulation 12, Rule 12, Flares at Petroleum Refineries

S1, Hydrogen Plant, will have a hydrogen plant flare for the purpose of flaring hydrogen and pressure swing absorption gas if there is an upset. BAAQMD Regulation 12, Rules 11 and 12, apply to petroleum refineries, which are defined for the purposes of the rule as:

> "A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 and including any associated sulfur recovery plant."

Because the hydrogen plant will not process petroleum, the hydrogen plant flare will not be subject to BAAQMD Regulation 12, Rules 11 and 12. The flare will be used exclusively to burn hydrogen, pressure swing absorption gas that is generated by the plant, and natural gas in the pilots for the flare. All three of these material are low in sulfur because the feed to the hydrogen plant is low in sulfur and sulfur is removed from the feed by a zinc oxide catalyst. If the feed to the hydrogen plant or the hydrogen plant furnace must be flared due to an upset, it will be burned in the refinery flares.

NSPS

Subpart D

This subpart applies to fossil-fuel fired steam generating units with a heat input over 250 MMbtu/hr. The definition of fossil-fuel fired steam generating unit in Section 60.41(a) is "a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer." S2, Hydrogen Plant Furnace, is not subject to 40 CFR 60, Subpart D, because it is primarily a furnace instead of a steam generating unit, although it does generate steam. In any case, S2 would easily comply with the 0.1 lb particulate matter/MMbtu standard in Section 60.42(a)(1) the 20% opacity standard in Section 60.42(a)(2), and the 0.2 lb NOx/MMbtu. S2 is expected to emit about 0.0037 lb PM10/MMbtu and 0.00658 lb NOx/MMbtu. Since the fuel will be very clean, it is not expected to have any visible emissions.

The standard does not contain a limit for sulfur dioxide for gaseous-fueled heaters.

Subpart Da
This subpart applies to electric utility steam-generating units with an electrical output that is higher than 25 MW per Sections 60.40Da and 60.41Da. Electricity will be generated at the hydrogen plant, but the output will be about 12 MW so S2, Hydrogen Plant Furnace, is not subject to the standard.

Subpart Db
This subpart applies to steam generating units with a heat input over 100 MMbtu/hr. The definition of steam generating units in Section 60.41b excludes process heaters, so S2, Hydrogen Plant Furnace, is not subject to the standard.

Subpart Dc
This subpart applies to steam generating units with a heat input over 10 MMbtu/hr and under 100 MMbtu/hr. The definition of steam generating units in Section 60.41c excludes process heaters, so S2, Hydrogen Plant Furnace, is not subject to the standard.

NSPS, Subpart J
S2, Hydrogen Plant Furnace, and S3, Flare, will be subject to 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries because they ~~it~~ will burn fuel gas as defined by the NSPS: "any gas which is generated at a petroleum refinery and which is combusted."

The heater will be subject to the H2S limit for fuel in Section 60.104(a)(1) of 0.10 gr/dscf or approximately 160 ppm. S2 will comply with the limit because it will burn either complying refinery fuel gas that will be supplied by the refinery, natural gas, or PSA gas, which is derived from the complying refinery fuel gas or natural gas and therefore cannot contain more H2S than the limit.

Air Liquide will be responsible for continuously monitoring the H2S content of the refinery, natural gas, and PSA gas at S2, Hydrogen Plant Furnace, as required by Section 60.105(a)(4). The permit conditions will also allow Air Liquide to install an SO2 CEM instead of monitoring the sulfur in the furnace and hydrogen plant feed as allowed by 40 CFR 60.105(a)(3).

The flare will also be subject to the H2S limit for fuel in Section 60.104(a)(1). The standard states:

> a) No owner or operator subject to the provisions of this subpart shall:
> (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

Process upset gases are defined in Section 60.101 as:

> *Process upset gas* means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

When the hydrogen plant sends gases to the flare due to a start-up, shut-down, upset or malfunction, the flare will not be subject to Section 60.104(a)(1). However, when the hydrogen plant sends gases to the flare due to "customer constraint", "contractual outage", or planned maintenance, the flare will be subject.

In any case, the flare will comply with the standard because it will only burn clean hydrogen or PSA gas. In those cases where the flare is subject to the standard, the facility will be required to monitor the H2S content of the gas continuously in accordance with Section 60.104, unless the facility obtains an alternative monitoring plan from USEPA.

EPA proposed changes to Subpart J on May 14, 2007, and intends to finalize changes by April 2008. If these changes allow the facility to monitor the H2S content in a different way or exempts some fuels from monitoring, the permit condition will allow Air Liquide to take advantage of changes in the standard when the changes are finalized.

MONITORING ANALYSIS

S1, Hydrogen Plant is subject to an annual throughput limit, cumulative increase limits of 4.35 lb POC/day from the deaerator vent and 8.2 lb fugitive POC/day, an ammonia limit of 0.64 lb/hr from the deaerator vent, and a limit on total sulfur in the feed to the hydrogen plant. The hydrogen plant is also subject to the combined organic compound limit in BAAQMD Regulation 8, Rule 2. The hydrogen plant will be subject to an annual source test to determine compliance with the deaerator vent limits. The owner/operator will determine compliance with the fugitive POC limit by using the methods in BAAQMD Regulation 8, Rule 18, Equipment Leaks. The total sulfur content of the feed to the hydrogen plant will be determined once per week at the outlet of the zinc oxide feed treatment system in the hydrogen plant by taking a grab sample and measuring it once per week. Alternately, the owner/operator may install an SO2 CEM on S2, Hydrogen Plant Furnace stack. Sulfur in the hydrogen plant feed is removed by the zinc oxide feed treatment system. The plant has two beds of zinc oxide and monitors sulfur at the outlet periodically. If the sulfur is removed from the feed, the syngas (PSA gas) that is fed to the hydrogen plant furnace and that provides approximately 85% of the heat input to the furnace should have no sulfur. Therefore, monitoring for sulfur in the feed is an effective method of ensuring that the syngas has no sulfur. Since the amount of zinc oxide should last at least nine months, monitoring on a weekly basis is sufficient monitoring. The owner/operator also has the option of installing an SO2 CEM on the S2, Hydrogen Plant Furnace, stack.

S2, Hydrogen Plant Furnace, has limits on hourly and annual heat input, concentration limits on NOx, CO, and NH3, lb/MMbtu limits on POC, SO2, and PM10, hourly and annual mass emission limits on NOx, CO, POC, PM10, and SO2, NH3, and sulfuric acid mist, and sulfur and H2S limits on the fuel. The heater will have a fuel meter to ensure compliance with the heat input limits. Since the heater is abated by SCR, it will have a NOx CEM to ensure that the abatement device is in compliance. A CO CEM was required by 40 CFR 63, Subpart DDDDD, before it was vacated by the DC Circuit Court on June 8, 2007. The District will require a CO CEM as part of case-by-case MACT pursuant to 40 CFR 63.52(a). The fuel gas will be monitored for H2S with a continuous emission monitor as required by 40 CFR 60, Subpart J, unless EPA amends the standard to allow another monitoring method. In addition, total sulfur will be monitored 3 times/day. The owner/operator will perform an annual test for compliance with the POC, PM10, SO2, sulfuric acid mist, and ammonia limits. Non-compliance with the POC and PM10 limits are not expected at this source. Since the source will be permitted to emit about 24 tpy of ammonia, the owner/operator will develop a correlation between the ammonia concentration and the ammonia injection rate. After the correlation is developed, the owner/operator will monitor ammonia continuously via the injection rate.

S3, Hydrogen Plant Flare

The flare is subject to annual limits for NOx, CO, POC, PM10, SO2 and a daily limit for NOx. Emissions will be monitored by installing a flow meter at the inlet to the flare and calculating the emissions for each event in the same manner as shown in Appendix A.

If gases are sent to the flare that are not considered to be startup, shutdown, malfunction, or upset gases, the facility must monitor the gases continuously for H2S in accordance with 40 CFR 60.104.

In addition, the flare is subject to standard conditions to determine if the 1.0 Ringelmann limit in BAAQMD Regulation 6-301 is exceeded during flaring events.

S4, Cooling Tower, is subject to monitoring of dissolved solids to ensure that the particulate matter emissions are as described in the permit application. It is also subject to visual monitoring, and chlorine content monitoring to ensure that POC emissions are as described. If POC emissions are found, the owner/operator must measure the POC emissions using EPA Laboratory Method 8015.

S5, Ammonia Tank: The tank is not expected to have emissions, so no monitoring has been imposed.
Overall annual emission limits have been imposed in Condition 23181, parts B.1-B.3, to ensure that the emissions of the project are less than the emissions proposed by the applicant. The reason that this condition has been imposed is to allow the facility to exceed certain limits during startup and shutdown and still comply with the annual limits. Part B.4 contains the monitoring and reporting for these limits.

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 November, 2006. 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 September 25, 2007, the final EIR was certified by the Contra Costa County Board of Supervisors. The District must act on the application within 30 days of the certification.

As a responsible agency, the District has prepared findings for the purposes of CEQA. They are attached in Appendix C.

NESHAPS
40 CFR 63, Subpart CC
The deaerator vents at the hydrogen plants are not considered miscellaneous process vents according to Section 60.641.

Relief valve discharges are not considered miscellaneous process vents.

40 CFR 63, Subpart DDDDD
S2, Hydrogen Plant Furnace, is subject to 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and

Institutional Boilers and Process Heaters. The DC Circuit Court vacated the standard on June 8, 2007. Where there is no MACT for a new source and the deadline for promulgation of a standard by EPA is past, local agencies must determine case-by-case MACT for the new source, in accordance with 40 CFR 63.52(a). The emission limit for S2 in the standard was 400 ppm CO. There were no other limits for gaseous-fueled boilers. A CO CEM was required for units over 100 MMbtu/hr.

The reason that the court gave for vacating the MACT was that EPA had inappropriately classified solid waste incineration units that were subject to Section 129 of the Clean Air Act as solid fuel units that were subject to the MACT. This classification greatly increased the number of units subject to the MACT and therefore skewed the determination of the MACT floor. The court stated that the "universe of units … will be far smaller and more homogenous [sic]" after the solid waste units were taken out of the group of units affected. The court expects that the rule will change substantially when EPA considers the smaller pool of units.

One possible outcome is that the standards may become more stringent because the HAP emissions from the solid waste incineration units are expected to be higher. The MACT "floor" is based on the performance of the top 12 percent of the units in a category.

EPA had determined that CO was an appropriate surrogate for organic HAPs. The argument was that high CO was indicative of poor combustion and therefore, poor destruction of organic HAPs. This is a reasonable assumption.

Following are the CO limits proposed by EPA:

- New, large and limited use solid fuel units: 400 PPM @ 7% O2
- Small solid fuel units: None
- New, large and limited use liquid fuel units: 400 PPM @ 3% O2
- Small liquid fuel units: None
- New, large and limited use gaseous fuel units: 400 PPM @ 3% O2
- Small gaseous fuel units: None
- Existing units None

Small units are defined as units with a capacity less than 10 MMbtu/hr.

Gaseous-fueled units are not expected to be sources of metallic or inorganic HAP.

The MACT limit for S2, therefore, was 400 PPM @ 3% O2, which is equivalent to the BAAQMD Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, which was adopted in 1992.

The District does not have the resources to survey all industrial, commercial, and institutional boilers and process heaters in the United States and determine the MACT "floor." However, the District notes that the CO BACT limit in the District's BACT workbook for boilers over 50 MMbtu/hr has been 50 ppmv since 2005. For refinery process heaters over 50 MMbtu/hr, the BACT limit has been 50 ppmv since 1994. The South Coast AQMD has had BACT limits for CO of 50 ppm for boilers since 2000.

On page 1680, column 3, second paragraph, of the MACT proposal published on January 13, 2003, EPA states:

> "The approach that we use to calculate the MACT floors for new sources is somewhat different from the approach that we use to calculate the MACT floors for existing sources. While the MACT floors for existing units are intended to reflect the average performance achieved by a representative group of sources, the MACT floors for new units are meant to reflect the emission control that is achieved in practice by the best controlled source. Thus, for existing units, we are concerned about estimating the central tendency of a set of multiple units, while for new units, we are concerned about estimating the level of control that is representative of that achieved by a single best controlled source."

If we agree with EPA that low CO levels indicate low levels of organic HAPs, then lower CO levels are better than higher CO levels. Considering that the "best controlled sources" have CO levels that are 50 ppm or lower, 400 ppm cannot be considered to be the proper MACT limit for a new gaseous-fueled source. The source is subject to a BACT CO limit of 10 ppm CO @ 3% O2. This level will be considered to be presumptive MACT for this source until EPA re-proposes and re-promulgates MACT. Since it is not expected that EPA will propose a limit that is lower than this limit, the source incurs no risk from this determination. Due to the size of the source, the CEM for CO will still be required.

40 CFR 70, Title V

The facility is subject to the Title V program because it is part of a major facility (the ConocoPhillips Refinery and Carbon Plant) as defined by BAAQMD Regulation 2-6-206. The definition of "Part 70 permit" in Section 70.2 acknowledges that a "group of permits" may cover a "source." (EPA's definition of "source" is similar to the District's definition of "facility.") Because more than one permit may be given to a facility, the District may grant a separate permit to Air Liquide.

The District will propose the Title V permit after the District has received public comment on and finalized the conditions.

40 CFR 72-78, ACID RAIN

Electricity will be generated using excess heat at the hydrogen plant. The hydrogen plant will not be subject to 40 CFR 72-78 because it will not sell electricity. The hydrogen plant or ConocoPhillips will consume all electricity that is produced. The standards apply only to "utilities," which are defined in 40 CFR 72.2 as "any person who sells electricity."

PSD

The discussion of the PSD analysis is contained in the engineering evaluation for Application 13424 and is hereby incorporated by reference. However, the conclusion will be restated here.

The combined project for the ConocoPhillips refinery, the Air Liquide hydrogen plant, and the ConocoPhillips Carbon Plant was subject to PSD because the emissions increase for PM10 was over 15 tons per year. After the permit was proposed, the applicants decided to reduce the PM10 emissions by 2 tons per year, which may be accomplished either by lowering the PM10 concentration or by curtailing operations, and to withdraw the PSD application. Therefore, the project is no longer a PSD project.

6. RECOMMENDATIONS

Issue a conditional authority to construct for the following sources:

S1, Hydrogen Plant (120 MMscf/day) including HRSG and steam turbine generator (12 MW)
S2, Hydrogen Plant Furnace, 1072 MMbtu/hr abated by A1, SCR
S3, Hydrogen Plant Flare, 2200 MMbtu/hr

Issue a letter of exemption to the following sources:

S4, Cooling Tower, 3,700 gpm (exempt per BAAQMD Regulation 2-1-128.4)
S5, Ammonia Tank, 10,000 gal 19% aqueous solution (exempt per BAAQMD Regulation 2-1-113.2)

7. PERMIT CONDITIONS

Any condition that is preceded by an asterisk is not federally enforceable.

"BAAQMD Regulation 2, Rule 5" replaces the following basis for permit conditions: "Toxics Risk Management."

CONDITION 23178

S1, Hydrogen Plant

1. The production of S1, Hydrogen Plant, shall not exceed 120 MMscf H2/day, averaged over any consecutive 12-months. [Cumulative Increase]

2. The owner/operator of the electrical generator associated with the hydrogen plant shall not generate more than 12 MW at any time. The owner/operator shall ensure that the hydrogen plant or the refinery consumes all of the electricity that is produced by the generator. [2-1-301, 2-1-305]

3. The owner/operator shall not burn any fuel in the HRSG associated with the S1, Hydrogen Plant. [2-1-301, 2-1-305]

4. The owner/operator shall ensure that the emissions of POC from the deaerator vent at S1 do not exceed 4.35 lb/day. [2-1-301, 2-1-305, Cumulative Increase]

5. The owner/operator shall ensure that the emissions of NH3 from the deaerator vent at S1 do not exceed 0.64 lb/hr. [Regulation 2, Rule 5]

6. The owner/operator shall ensure that the fugitive emissions of POC from the components (valves, flanges, pumps, compressors, connectors, sample points, etc.) at the hydrogen plant do not exceed 3,000 lb/year. [Cumulative Increase, 2-1-305]

7. The owner/operator shall ensure that the concentration of total sulfur in the feed to the hydrogen plant does not exceed 35 ppmv. [Cumulative Increase, 2-1-305]

8. The owner/operator shall measure total sulfur at the outlet of the zinc oxide feed treatment system in the hydrogen plant by taking a grab sample and measuring it once per week. Alternately, the owner/operator may install an SO2 CEM on S2, Hydrogen Plant Furnace stack. [BACT, Cumulative Increase]

9. No later than 90 days from the startup of S1 and every year thereafter, the owner/operator shall conduct a District-approved source test to determine compliance with the limit in Parts 4 and 5 for POC and NH3. The owner/operator shall conduct the POC source tests in accordance with the Manual of Procedures, Volume IV, Method ST-7 or EPA Method 25 or 25A. The owner/operator shall conduct the NH3 source tests in accordance with the Manual of Procedures, Volume IV, Method ST-1B. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test. [Cumulative Increase, 2-1-305]

10. The owner/operator shall ensure that all pressure relief devices on the process unit are vented to a fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency of 98%. [8-28-302, BACT]

Fugitive Components at S1, Hydrogen Plant, and S2, Hydrogen Plant Furnace

11a. The owner/operator shall equip all new light hydrocarbon control valves installed at S1 and S2 with live loaded packing systems and polished stems, or equivalent.
[BACT]

11b. The owner/operator shall comply with a leak standard of 100 ppm of TOC (measured as C1) at any new valve installed at S1 and S2. The owner/operator shall not be considered in violation of the leak standard if the owner/operator complies with the applicable minimization and repair provisions contained in Regulation 8, Rule 18. [BACT, Regulation 8, Rule 18]

12. The owner/operator shall equip all new flanges/connectors installed in the light hydrocarbon piping systems at S1 and S2 with graphitic-based gaskets unless the service requirements prevent this material. [BACT]

13. The owner/operator shall equip all new hydrocarbon centrifugal compressors installed at S1 and S2 with "wet" dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas. [BACT]

14. The owner/operator shall equip all new light hydrocarbon centrifugal pumps installed at S1 and S2 with a seal-less design or with dual mechanical seals with a heavy liquid barrier fluid, or equivalent. [BACT]

15. The owner/operator shall comply with a leak standard of 100 ppm of TOC (measured as C1) at any new pumps and/or compressors installed at S1 and S2. The owner/operator shall not be considered in violation of the leak standard if the owner/operator complies with the applicable minimization and repair provisions contained in Regulation 8-18. All pumps and/or compressors subject to the leak standard of 100 ppm TOC shall be included in the total number of pumps and compressors used in Regulation 8-18-306.2 to determine the total number of non-repairable pumps and compressors allowed. [BACT] [BACT]

16. The Owner/Operator shall submit a count of installed pumps, compressors, valves, and flanges/connectors every 180 days starting the startup date of the first unit, S1 or S2, until construction is complete. 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 (948 valves in gas service, 48 valves in light liquid service, 4,193 flanges in gas service, 98 flanges in light liquid service, 5 pumps in light liquid service, 4 sample connections in gas service, 3 compressors in gas service) with a total POC emission rate of 1.5 ton/yr. The exact number of components may change without penalty. 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, Regulation 2, Rule 5]

(The sentence about changes in the exact number of components has been added in response to a comment by the applicant. This note will be removed in the final permit conditions.)

17. Inspections

The owner/operator shall conduct inspections of new fugitive components installed at S1 and S2 in light hydrocarbon service with an initial boiling point less than or equal to 302 degree F in accordance with the frequency listed below:

Pumps: Quarterly
Compressors: Quarterly
Valves: Quarterly

Connectors (Not Flanges): Annual
Flanges: Annual
[BACT, Regulation 8, Rule 18]

18. In order to determine compliance with part 6, the owner/operator shall determine the daily emissions of fugitive components within 90 days of start-up, and within 30 days of the end of every calendar quarter thereafter. The owner/operator shall use the last concentration measured in accordance with BAAQMD Regulation 8, Rule 18, for each component. The owner/operator shall use the equations in ARB publication California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities. [Cumulative Increase, Regulation 2-1-305]

CONDITION 23179

S2, Hydrogen Plant Furnace

1. S2 shall use only pressure swing adsorption (PSA) off gas, refinery fuel gas and pipeline quality natural gas as fuel. [Cumulative Increase]

2. Total fuel firing at S2 shall not exceed 9,636,000 MMbtu (HHV) over any consecutive 12-month period. [Cumulative Increase]

3. Total fuel firing at S2 shall not exceed 1,072 MMbtu (HHV) during any clock hour. [Cumulative Increase]

4. The owner/operator shall ensure that the feed to S2 does not contain more than 35 ppmv total sulfur. [BACT, Cumulative Increase, 2-1-305]

5. The following emission concentration limits from S2 shall not be exceeded. These limits shall not apply during startup periods not exceeding 24 hours (120 hours when drying refractory or during the first startup following catalyst replacement) and shutdown periods not exceeding 24 hours. The District may approve other startup and shutdown durations.

   a. NOx: 5 ppmv @ 3% oxygen, averaged over any clock hour [BACT]
   b. CO: 10 ppmv @ 3% oxygen, averaged over any 1 hour period [BACT, 40 CFR 63.52(a)]
   c. POC: 0.0027 lb/MMbtu, averaged over any 1 hour period [BACT]
   d. PM10: 0.0037 lb/MMbtu, averaged over any 1 hour period [BACT]
   e. SO2: 0.0012 lb/MMbtu, averaged over any 1 hour period [BACT]
   [BACT]

(The manufacturer requires 120 hours for the drying of refractory or after a catalyst change. This is allowable because the emissions will be within the annual limits. This note will be removed in the final permit conditions.)

6. *The following emission concentration limits from S2 shall not be exceeded. NH3: 10 ppmv @ 3% oxygen (8 hr average) [Regulation 2, Rule 5]

7a. The following hourly mass emission limits from S2 shall not be exceeded. These limits shall not apply during startup periods not exceeding 24 hours (120 hours when drying refractory or during the first startup following catalyst replacement) and shutdown periods not exceeding 24 hours. The District may approve other startup and shutdown durations.

a. NOx: 7.5 lb per clock hour [BACT]
b. CO: 9.1 lb per clock hour [BACT]
c. POC: 3.5 lb per clock hour [BACT]
d. PM10: 4.8 lb per clock hour [BACT]
e. SO2: 1.5 lb per clock hour [BACT]

7b. The following hourly mass emission limit from S2 shall not be exceeded.
a. NOx: 50 lb per clock hour [BACT]
[BACT]

8. *The following hourly mass emission limit from S2 shall not be exceeded.
a. NH3: 6.5 lb per clock hour
[Regulation 2, Rule 5]

9. The following hourly mass emission limit from S2 shall not be exceeded.
a. Sulfuric acid mist: 0.098 lb per clock hour
[Regulation 2, Rule 5, PSD]

10. The following annual mass emission limits from S2 shall not be exceeded including periods of startup, shutdown, upset and malfunction:
a. NOx: 28.1 tons per any consecutive 12 months [BACT]
b. CO: 34.2 tons per any consecutive 12 months [BACT]
c. POC: 11.5 tons per any consecutive 12 months [BACT]
d. PM10: 13.8 tons per any consecutive 12 months [BACT]
e. SO2: 5.0 tons per any consecutive 12 months [BACT]
[Cumulative Increase]

11. *The following annual mass emission limits from S2 shall not be exceeded including periods of startup, shutdown, upset and malfunction.
a. NH3: 48,200 lb per any consecutive 12 months
[Regulation 2, Rule 5]

12. The following annual mass emission limits from S2 shall not be exceeded including periods of startup, shutdown, upset and malfunction.
a. Sulfuric acid mist: 860 lb any consecutive 12 months
[2-1-305, Regulation 2, Rule 5, PSD]

13. A1, SCR unit, shall abate the S2, Hydrogen Plant Furnace, at all times, with the following exceptions. Operation of A1 is not required for limited periods during startup and shutdown. S2 may operate without SCR abatement on a temporary basis for periods of planned or emergency maintenance. A District-approved NOx CEM shall monitor and record the S2 NOx emission rate whenever S2 operates without abatement. All emission limits

applicable to S2 shall remain in effect even if it is not operated with SCR abatement. [BACT, Cumulative Increase]

14a. The owner/operator shall test refinery fuel gas prior to combustion at S2 to determine total sulfur concentration with a total sulfur analyzer (Houston Atlas or equivalent) 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. To demonstrate compliance with Part 4, the owner/operator shall measure and record the daily average sulfur content. The owner/operator shall keep records of sulfur content in fuel gas for at least five years and shall make these records available to the District upon request. The owner/operator is not required to test PUC-quality natural gas for total sulfur. If the sulfur content of feed to S1, Hydrogen Plant, is monitored in accordance with Condition 23178, part 8, and the sulfur content is less than 35 ppmv, the owner/operator is not required to test PSA gas for total sulfur. [BACT, Cumulative Increase]

14b. If the owner/operator elects to install a SO2 CEM at the S2, Hydrogen Plant Furnace, stack, the owner/operator is not required to perform the monitoring in Condition 23178, parts 7 and 8 and Condition 23179, parts 4, 14a, and 15. In this case, the monitor shall comply with BAAQMD Manual of Procedures, Volume V, and 40 CFR 60.105(a)(3). The monitor shall be used to determine compliance with the SO2 limits in 40 CFR 60.105(a)(3) of 20 ppmdv @ 0% O2, the lb/MMbtu limit in part 5e, the hourly limit in part 7a, and the annual limits in part 10 and Condition 23181, part B.2.

(Parts 14b has been amended at the applicant's request to allow the use of SO2 CEM monitoring that is allowed by Condition 23179, part 14b, to determine compliance with the annual limits. This note will not appear in the final permit conditions.)

15. The owner/operator shall install, calibrate, maintain, and operate a District-approved continuous monitoring system and recorder for H2S in the gas that is burned by the heater. The owner/operator shall keep the H2S data for at least five years and shall make these records available to the District upon request. If USEPA amends 40 CFR 60, Subpart J, such that a continuous monitoring system is not required for this heater, the owner/operator will not be required to install the system. If the system has been installed, the owner/operator may remove the system. [40 CFR 60.105(a)(4), Cumulative Increase]

16. No later than 90 days from the startup of S2, the owner/operator shall conduct District-approved source tests to determine initial compliance with the limits in Parts 5, 6, 7, 8, and 9 for NOx, CO, POC, PM10, NH3, SO2, sulfuric acid mist, and POC. The owner/operator shall conduct the source tests in accordance with Part 18. The owner/operator shall submit the

source test results to the District source test manager and the District Director of Compliance and Enforcement no later than 60 days after the source test. [BACT, Cumulative Increase, PSD]

17. On an annual basis, the owner/operator shall conduct District-approved source tests to determine compliance with the limits in Parts 5c, 5d, 5e, 7c, 7e, 7e, 8, and 9 for POC, PM10, NH3, SO2, and sulfuric acid mist. The owner/operator shall conduct the source tests in accordance with Part 18. The owner/operator shall submit the source test results to the District source test manager and the District Director of Compliance and Enforcement no later than 60 days after the source test.
[BACT, Cumulative Increase, PSD, Regulation 2, Rule 5]

18. The owner/operator shall submit protocols for all source test procedures to 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, PSD]

19. The following instruments shall be installed and maintained to demonstrate compliance with Parts 5a, 5b, 7a, 7b, 9a and 9b, BAAQMD Regulation 1-520 and 40 CFR 63.52:
a. continuous NOx analyzer/recorder
b. continuous CO analyzer/recorder
c. continuous O2 or CO2 analyzer/recorder
The instruments shall operate at all times of operation of S2 including start-up, shutdown, upset, and malfunction, except as allowed by BAAQMD Regulation 1-522, BAAQMD Manual of Procedures, Volume V, and 40 CFR 63, Subpart DDDDD. If necessary to comply with this requirement, the owner/operator shall install dual-span monitors.
[1-520, BACT, Cumulative Increase, 40 CFR 63.52(a)]

20. The owner/operator shall equip S2 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]

21. Ammonia (NH3) emission concentrations at the hydrogen plant stack shall not exceed 10 ppmv, on a dry basis, corrected to 3% O2, on a clock hour basis. This ammonia emission concentration shall be verified by the continuous recording of the ammonia solution injection rate to A1, SCR. The correlation between the heat input rates, the SCR ammonia solution injection rates, and corresponding ammonia emission concentration at the hydrogen plant stack shall be determined in accordance with permit condition 23. (Regulation 2, Rule 5)

22. The owner/operator shall demonstrate compliance with part 21 by using a properly operated and maintained continuous monitor (during all hours of operation including start-up and shutdown periods) for the ammonia solution injection rate. The owner/operator shall record the ammonia solution injection rate every 15 minutes (excluding normal calibration periods) and shall summarize the ammonia solution injection rate for each clock hour. (Regulation 2, Rule 5)

23. Within 60 days of start-up of the hydrogen plant furnace, the owner/operator shall conduct a District-approved source test on at the hydrogen plant stack to determine the corrected ammonia emission concentration to determine compliance with part 21. The source test shall determine the correlation between the heat input rates of the hydrogen plant furnace, the ammonia solution injection rate, and the corresponding ammonia emission concentration at the emission point. The source test shall be conducted over the expected operating range of the hydrogen plant furnace to establish the range of ammonia solution injection rates necessary to achieve NOx emission reductions while maintaining ammonia slip levels. Source testing shall be repeated on an annual basis thereafter. Ongoing compliance with part 21 shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia solution injection rate. Source test results shall be submitted to the District within 45 days of conducting the tests. (Regulation 2, Rule 5)

CONDITION 23180

S3, Hydrogen Plant Flare

1. The owner/operator shall ensure that only the following streams are sent to S3, Hydrogen Plant Flare:
   a. Hydrogen
   b. Syn-gas
   c. Venting from the ammonia tank
   d. PSA Offgas

   The owner/operator shall ensure that any feed for S1, Hydrogen Plant, or any fuel including natural gas that is provided to S2, Hydrogen Plant Furnace, is not flared in S3, Hydrogen Plant Flare.
   [2-1-305]

2. S3, Hydrogen Plant Flare, may be used during startup, shutdown, upset, or malfunction of S1, Hydrogen Plant, loss of the PSA process, PSA maintenance, contractual outage, and customer constraint, as long as the emissions do not exceed the limits in part 4. [2-1-305, Cumulative Increase]

3. The owner/operator shall install a flow meter to determine the flow of gases to the flare. The flow meter shall comply with the requirements for flow meters in BAAQMD Regulation 12, Rule 11. [Cumulative increase]

4. The owner/operator shall ensure that the emissions of S3, Hydrogen Plant Flare, do not exceed the following limits:
   a. NOx: 2.8 tons/any consecutive 12 months [Cumulative increase]
   b. CO: 12.1 tons/any consecutive 12 months [Cumulative increase]
   c. NOx: 129 lb/any consecutive 60 minutes [2-1-403, CAAQS]

5. The owner/operator shall estimate the emissions every month by using the flow data to the flare and estimating emissions using the emission factors provided in Application 13678. [Cumulative increase]

6. If the limits in parts 4a and 4b are exceeded, the owner/operator shall apply to increase the annual limit within 60 days of determining that the limit has been exceeded, and shall provide offsets for the increase in the limits. If the limit in part 4c is exceeded, the owner/operator shall determine using PSD modeling if the CAAQS or NAAQS for NO2 was exceeded during the event, and if so, shall report the exceedance to the BAAQMD Director of Enforcement and Compliance. [2-1-403, CAAQS, Cumulative increase]

7. For the purposes of these conditions, a flaring event is defined as a flow rate of vent gas flared in any consecutive 15 minutes period that continuously exceeds 330 standard cubic feet per minute (scfm). If during a flaring event, the vent gas flow rate drops below 330 scfm and then increases above 330 scfm within 30 minutes, that shall still be considered a single flaring event, rather than two separate events. For each flaring event during daylight hours (between sunrise and sunset), the owner/operator shall inspect the flare within 15 minutes of determining the flaring event, and within 30 minutes of the last inspection thereafter, using video monitoring or visible inspection following the procedure described in Part 8. [Regulation 2-6-409.2]

8. The owner/operator shall use the following procedure for the initial inspection and each 30-minute inspection of a flaring event.

~~a. If the owner/operator can determine that there are no visible emissions using video monitoring, then no further monitoring is necessary for that particular inspection.~~

b. If the owner/operator cannot determine that there are no visible emissions using video monitoring, the owner/operator shall conduct a visual inspection outdoors using either:
   i. EPA Reference Method 9; or
   ii. Survey the flare by selecting a position that enables a clear view of the flare at least 15 feet, but not more than 0.25 miles, from the emission source, where the sun is not directly in the observer's eyes.

c. If a visible emission is observed, the owner/operator shall continue to monitor the flare for at least 3 minutes, or until there are no visible emissions, whichever is shorter.
d. The owner/operator shall repeat the inspection procedure for the duration of the flaring event, or until a violation is documented in accordance with Part 9. After a violation is documented, no further inspections are required until the beginning of a new calendar day.
[Regulation 6-301, 2-1-403]

9. The owner/operator shall comply with one of the following requirements if visual inspection is used:

~~a. If EPA Method 9 is used, the owner/operator shall comply with Regulation 6-301 when operating the flare.~~

~~b. If the procedure of Part 8.b.ii is used, the owner/operator shall not operate a flare that has visible emissions for three consecutive minutes.~~
[Regulation 2-1-403]

10. The owner/operator shall keep records of all flaring events, as defined in Part 7. The owner/operator shall include in the records the name of the person performing the visible emissions check, whether video monitoring or visual inspection (EPA Method 9 or visual inspection procedure of Part 8) was used, the results of each inspection, and whether any violation of this condition (using visual inspection procedure in Part 8) or Regulation 6-301 occurred (using EPA Method 9). [Regulation 2-1-403]

11. The owner/operator will ensure that S3, Flare, complies with all applicable provisions of 40 CFR 60, Subpart J. This provision will be deleted when the applicable citations from this standard are incorporated into the Major Facility Review permit. [40 CFR 60, Subpart J]

12. The owner/operator shall install, calibrate, maintain, and operate a District-approved continuous monitoring system and recorder for H2S in the gas that is burned by the flare. The owner/operator shall keep the H2S data for at least five years and shall make these records available to the District upon request. If USEPA amends 40 CFR 60, Subpart J, such that a continuous monitoring system is not required for this flare, the owner/operator will not be required to install the system. If the system has been installed, the owner/operator may remove the system. [40 CFR 60.105(a)(4), Cumulative Increase]

An annual PM10 limit for sources in Facilities A0016 and B7419 was added to ensure that the CFEP project does not exceed PSD thresholds for PM10.

CONDITION 23181

A. Facility Conditions

1. *The owner/operator shall notify the District in writing by fax or email no less than three calendar days in advance of any scheduled startup or shutdown

of any process unit, and, for any unscheduled startup or shutdown of a process unit, within 48 hours or within the next normal business day. The notification shall be sent in writing by fax or email to the Director of Enforcement and Compliance. This requirement is not federally enforceable. [Regulation 2-1-403]

2. The owner/operator shall ensure that the concentration of ammonia in the ammonia tank is less than 20% by weight so that 40 CFR 68, Accidental Release, does not apply. [2-1-305]

<u>B. Project Mass Emission Limits</u>

1. Following are the sources that are subject to the project mass emission limits:
   S1, Hydrogen Plant including HRSG and steam turbine generator
   S2, Hydrogen Plant Furnace
   S3, Hydrogen Plant Flare
   [Cumulative Increase, 2-1-403]

2. The owner/operator shall ensure that the annual emissions of the above sources do not exceed the following annual emission limits, including periods of startup, shutdown, malfunction, and upset emissions.

a.	NOx	30.9 tpy [Cumulative Increase, 2-1-403]
b.	SO2	5.0 tpy [Cumulative Increase, 2-1-403]
c.	PM10	13.8 tpy [Cumulative Increase, 2-1-403]
d.	POC	13.9 tpy [Cumulative Increase, 2-1-403]
e.	CO	46.2 tpy [Cumulative Increase, 2-1-403]
f.	Sulfuric acid mist	0.43 tpy [PSD]
*g.	Ammonia	26.9 tpy [Regulation 2, Rule 5]

3. The owner/operator shall ensure that the daily emissions of the above sources do not exceed the following daily emission limit, including periods of startup, shutdown, malfunction, and upset emissions.

a.	Sulfuric acid mist	2.35 lb/day [PSD]

4. The owner/operator shall determine whether the emissions are below the allowable mass emissions for the above sources as shown below. The owner/operator calculate and report the emissions of NOX, SO2, PM10, POC, CO, ammonia, and sulfuric acid mist on an annual basis in the following manner.
   a. The owner/operator shall the use the POC emission rate determined by the annual source test data at the deaerator for S1.
   b. The owner/operator shall use the data generated by the BAAQMD Regulation 8, Rule 18, monitoring to determine the annual POC emission rate for the components.
   c. The owner/operator shall use the mass emissions data generated by the NOx and CO CEMs at S2.
   d. The owner/operator shall use the monitoring for total sulfur in the feed to the hydrogen plant or CEM monitoring of SO2 at the outlet of the hydrogen plant furnace.

e. The owner/operator shall use the monitoring for total sulfur in the feed to the hydrogen plant furnace or CEM monitoring of SO2 at the outlet of the hydrogen plant furnace.
f. The owner/operator shall use the emission rates of sulfuric acid mist, PM10, POC, and CO determined in annual source tests at S2 and the records of heat input to calculate emissions of sulfuric acid mist, PM10, POC, and CO.
g. The owner/operator shall use the ammonia injection monitoring and the records of heat input to calculate emissions of ammonia.
h. The owner/operator shall use the calculations of flare emissions required by BAAQMD Condition 23180, part 5.

[2-1-305]

(Parts 4d and 4e have been amended to allow the use of SO2 CEM monitoring that is allowed by Condition 23179, part 14b. This note will not appear in the final permit conditions.)

5. If the annual emissions, as determined in part B.4, are above the allowable emissions for the project, the owner/operator shall supply additional offsets, where applicable, and perform additional analysis for PSD, if necessary. The results of the analysis shall be submitted to the Director of Compliance and Enforcement on an annual basis on the anniversary of the startup of S2, Hydrogen Plant Furnace. [2-1-403]

6. The annual emissions of the following sources shall not exceed 16.3 tons PM10/yr: S45, S434, and S1004 at Facility A0016, and S2 and S3 at Facility B7419. If the emissions exceed 16.3 tons in any consecutive 12 month period, the owners/operators of Facilities A0016 and B7419 shall provide contemporaneous offsets of PM10 that comply with BAAQMD Regulations 2-2-201 and 2-2-605. [1-104, 2-2-304]

7. The owner/operator shall comply with the requirements of BAAQMD Regulation 8, Rule 18. (This part will be deleted after the Title V permit is issued.) [BAAQMD Regulation 8, Rule 18]

CONDITION 23414

S4, Cooling Tower

1. The owner/operator shall ensure that the cooling tower is designed to have a drift of no more than 0.005% of total cooling water flow. [Cumulative Increase]

2. The owner/operator shall ensure that the dissolved solids content in the cooling water at S4, Cooling Tower, does not exceed 3000 ppm total dissolved solids. [Cumulative Increase]

3. The owner/operator shall take a sample and perform a visual inspection of the cooling tower water at the cooling tower on a daily basis to check for signs of hydrocarbon in the cooling water. (Regulation 2-6-503)

4. The owner/operator shall take a sample of the cooling tower water 3 times per week at the cooling tower and analyze for chlorine content as an indicator of hydrocarbon leakage into the cooling water. On a monthly basis, the owner/operator shall sample the water in the inlet line and in the return line of the cooling tower and determine the VOC content in each line using EPA laboratory method 8015. (Regulation 2-6-503)

5. The owner/operator shall maintain monthly records of sodium hypochlorite usage at each cooling tower above. (Regulation 2-6-501)

6. The owner/operator shall sample the cooling tower water at least once per month and subject the sample to a District approved laboratory analysis to determine its total dissolved solids content. (Regulations 2-6-503)

7. If the monitoring in part 3 or part 4 indicates that there is a hydrocarbon leak into the cooling water, the owner/operator shall submit a report to the Enforcement and the Engineering divisions at the District. The owner/operator shall submit reports on a weekly basis until the monitoring indicates that no hydrocarbon leaks into the cooling water.
(Regulation 1-441)

8. If the monitoring in part 3 or part 4 indicates a hydrocarbon leak, the owner/operator shall estimate the daily amount of VOC emitted using the following procedure. The owner/operator shall sample the water in the inlet line and in the return line and determine the VOC content in each line using EPA laboratory method 8015. This analysis shall be performed each week until VOC levels return to normal. The owner/operator shall report the VOC estimates to the Enforcement and the Engineering divisions at the District on a monthly basis. The owner/operator shall use the VOC estimates to confirm that no more than 5 tons VOC per year was emitted at the source. If more than 5 tons VOC per year is emitted at the source, the facility shall submit an application for a District permit within 90 days of determining that the source is subject to District permits. If the source requires a permit, the source shall be subject to BACT and offsets. (Regulations 1-441, 2-1-424, 2-6-416.2, 2-6-501, 2-6-503)

9. The owner/operator shall maintain the following records for five years from the date of record:
   a. Records of daily visual inspection
   b. Records of chlorine content 3 times per week
   c. Records of monthly usage of sodium hypochlorite
   d. Records of monthly determination of total dissolved solids
   e. Records of any indications of hydrocarbon leaks
   f. Records of any analyses of VOC content in cooling tower inlet and outlet

   (Regulation 2-6-501)

By: ____ October 5, 2007

Brenda Cabral — Date

Supervising Air Quality Engineer

Appendix A

S1, Hydrogen Plant Emissions

The detailed calculations are available in electronic format upon request.

S2, Hydrogen Plant Furnace Emissions

The following emission calculations have been submitted by the applicant.

Hydrogen Plant Furnace Criteria Pollutant Emission Factors
Air Liquide Hydrogen Plant Operational Emissions

Pollutant	Emission Factor		EF (lb/MMBtu)	Reference
NOx	5	ppmvd @ 3% O_2	0.00658	SCAQMD BACT
SO_2	35	ppmv total S in RFG/NG	0.0012	BAAQMD BACT (PSA/fuel gas Mix)
PM10	3.8	lb/MMcf (natural gas)	0.0037	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H2 in fuel)
POC	2.75	lb/MMcf (natural gas)	0.0027	AP42 Section 1.4, Natural Gas Combustion (apply 1/2 value since 50% H2 in fuel)
CO	10	ppmvd @ 3% O_2	0.0080	SCAQMD BACT

Assumptions for emissions factor table above:
(1) NOx, CO, and NH3 "ppm" emission factors converted to "lb/MMBtu" as follows:
(x [lb/MMBtu]) = (y ppm @ 3% O2) * (21% - 0%) / (21% - 3%) * (EPA Fd Factor [ft3/MMBtu]) / (Molar Volume [ft3/lbmol]) * (Molecular weight [lb/lbmol])

PM10 and POC "lb/MMcf" emission factors converted to "lb/MMBtu" as follows:
(x [lb/MMBtu]) = (Emission factor [lb/MMcf]) / (Natural gas heat content [Btu/scf])

Fd Factor:	9290	ft3/MMBtu (Air Liquide)
Molar volume:	379	ft3/lbmol (at STP: 25 C, 1 atm)
NOx MW:	46	lb/lbmol
CO MW:	28	lb/lbmol
NH3 MW:	17	lb/lbmol
SO2 MW:	64	lb/lbmol
PSA gas:	235	Btu/scf (ConocoPhillips)
Refinery Fuel Gas:	1340	Btu/scf (ConocoPhillips 3 year average)
Natural Gas	1020	Btu/scf (AP42 basis)

New Hydrogen Plant Furnace Criteria Pollutant Emissions

Criteria Pollutant	**Emissions**		
	lb/hr(1)	**lb/day(1)**	**ton/yr**
NOx	7.1	169	28.1
SO_2	1.2	30	5.0
PM10	4.0	95	15.8
POC	2.9	69	11.5
CO	8.6	206	34.2

Notes:
(1) Assumed heater rating:

Maximum daily:	1,072	MMBtu/hr
annual:	975	MMBtu/hr
Hydrogen plant capacity:	120	MMscf/day

The emission estimates above are based on an annual average heat input of 975 MMbtu/hr for 8760 hours per day. The facility has decided to limit the PM10 emissions at the furnace to 13.8 tons per year, which will either be accomplished by demonstrating that emissions are lower than 0.0037 lb/MMbtu or by curtailing operations. The resulting emissions are:

Revised **New Hydrogen Plant Furnace Criteria Pollutant Emissions**

	Emissions		
Criteria Pollutant	**lb/hr(1)**	**lb/day(1)**	**ton/yr**
NOx	7.1	169	28.1
SO_2	1.2	30	5.0
PM10	4.0	95	13.8[2]
POC	2.9	69	11.5
CO	8.6	206	34.2

Notes:

(1) Assumed heater rating:

Maximum daily:	1,072	MMBtu/hr
annual:	975	MMBtu/hr
Hydrogen plant capacity:	120	MMscf/day

(2) Based on permit limit

S3, Hydrogen Plant Flare Emissions

The following emission calculations have been submitted by the applicant.

Estimated Flare Emissions
Air Liquide Hydrogen Plant Operational Emissions

I. NOx and CO Factors

0.0641 lb NOx/MMBtu (TCEQ factor for non-steam assist, low-Btu flare, LHV)
0.5496 lb CO/MMBtu (TCEQ factor for non-steam assist, low-Btu flare, LHV)
98% DRE for CO

II. Summary

Source	Pollutant	lb/hr	tpy
Pilot/Sweep Emissions	NOx	0.03	0.12
	CO	0.24	1.07
	SO2	0.0004	0.004

III. Calculations

A. Pilot Emissions

4 Pilots
91.9 scfh/pilot, Natural Gas
367.6 scfh total for pilots

116.7	scfh sweep gas, Natural Gas
484.3	scfh total for pilots and sweep gas
919	Btu/scf, Natural Gas LHV
10	Ppmv Sulfur in NG

NOx

484.3	scf NG	919	Btu	0.0641	lb NOx	1	MMBtu	=	0.028529 lb NOx
	hr		scf NG		MMBtu	1000000	Btu		hr
0.03	lb NOx	8760	hr	1	ton			=	0.124957 tons NOx
	hr		yr	2000	lb				yr

CO

484.3	scf NG	919	Btu	0.5496	lb CO	1	MMBtu	=	0.244611 lb CO
	hr		scf NG		MMBtu	1000000	Btu		hr
0.24	lb CO	8760	hr	1	ton			=	1.071398 tons CO
	hr		yr	2000	lb				yr

SO2

10	ft3 S	484.3	scf NG	1	lbmol S	32	lb S	=	0.000402 lb S
1000000	ft3 NG		hr	385.3	ft3 S		lbmol S		hr
0.0004	lb S	64	lb SO2					=	0.001 lb SO2
	hr	32	lb S						hr
0.00	lb SO2	8760	hr	1	ton			=	0.004 tons SO2
	hr		yr	2000	lb				yr

B. Customer Constraint

2.79	mmscfh of hydrogen
6	events per year
3.75	Hours per event
274	Btu/scf, HHV Hydrogen

NOx

2.79	mmscf H2	274	MMBtu	0.0641	lb CO			=	49.00 lb NOx
	hr		mmscf		MMBtu				hr

49.00	lb NOx	3.75	hours	6	events	1	ton	=	0.55 tons NOx
	hr		event		yr	2000	lbs		yr

C. Loss of PSA

7.74	mmscfh syngas
0.0516	scf Methane/scf Syngas
909	Btu/scf, methane
261.1	Btu/scf, syngas
835.31	Lbmol/hr CO
28	lb CO/lbmol
98%	DRE for CO
1	Event/yr
5.3	hrs/event

CO

thermal

7.74	mmscf Syngas	0.0516	scf Methane	909	MMBtu	0.5496	lb CO	=	199.53 lb CO
	hr		scf Syngas		MMscf		MMBtu		hr

destroyed

835.31	lbmol CO	28	lb CO	0.98	DRE			=	467.77 lb CO

	hr		lbmol CO							hr

667.30	lb CO	1	event	5.3	hrs	1	ton	=	1.77	tons CO
	hr		yr		event	2000	lbs			yr

NOx

7.74	mmscf Syngas	261.1	MMBtu	0.0641	lb NOx			=	129.54	lb NOx
	hr		MMScf SG		MMBtu					hr

129.54	lb NOx	1	event	5.3	hrs	1	ton	=	0.34	tons NOx
	hr		yr		event	2000	lbs			yr

D. PSA Maintenance

Since the PSA has 12 beds, emissions are estimated by taking 2/12ths of the emissions from losing the entire PSA.

6 events/yr
1 hr/event

NOx	21.59	lb/hr
	0.06	Tpy
CO	111.22	lb/hr
	0.33	Tpy

E. Plant Maintenance

Maximum flaring will occur when the plant is operating at 50% capacity. Therefore, emissions are estimated by taking 1/2 of the Loss of PSA case.

2 events/yr
9 hrs/event

NOx	64.77	lb/hr
	0.57	tpy
CO	333.65	lb/hr
	2.94	tpy

F. Contractual Outage

Maximum flaring will occur when the plant is operating at 50% capacity. Therefore, emissions are estimated by taking 1/2 of the Loss of PSA case.

	4	events/yr
	9	hrs/event
NOx	64.77	lb/hr
	1.15	tpy
CO	333.65	lb/hr
	5.94	tpy

Total Estimated Flare Process Emissions

NOx	2.68	tpy
CO	10.98	tpy

S4, Cooling Tower

Table 3-7

Estimated Hydrogen Plant Cooling Tower Emissions

Operations parameter	Value
Tower Capacity, MM gal/day	5.3
Maximum water hardness, ppm TDS	1300
Drift Loss, % of flow capacity[1]	0.0044%
Weight of water, lb/gal	8.34
Maximum PM10 emissions, lb/yr[2]	927.7
Maximum PM10 emissions, ton/yr[2]	0.46
POC Emission Factor [3]	1.50
Maximum POC emissions, lb/day	8.0
Maximum POC emissions, lb/yr	2917
Maximum POC emissions, ton/yr	1.5

[1]Vender Estimate

[2]Calculation method from Section VI (Engineering Evaluation Template) of BAAQMD Permit Handbook Chapters, Cooling Towers

[3]EPA AP-42 Table 5.1-2. Uncontrolled emission factor is 6 lbs POC/MMgal. Emission factor reduced to 1/4 of referenced value due to POC content of stream.

APPENDIX B

ConocoPhillips Analysis of BACT for NOx and PM10 for Facility A0016, ConocoPhillips Refinery, and Facility B7419, Air Liquide

Following is ConocoPhillips' review of Best Available Control Technology for S45, Heater, S1004, Sulfur Recovery Unit, and Facility B7149, S2, Heater from Prevention of Significant Deterioration Application submitted on June 2, 2006

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

This section addresses BACT requirements for the proposed ConocoPhillips CFEP, as well as the related new Hydrogen Plant on the Refinery site to be owned and operated by Air Liquide Large Industries U.S. LP.

BAAQMD Rule 2-2-301 requires BACT to be applied to:

"…any new or modified source which results in an emission from a new source, or an increase in emissions from a modified source, and which has the potential to emit 10.0 pounds or more per highest day of precursor organic compounds (POC), non-precursor organic compounds (NPOC), nitrogen oxides (NO_x), sulfur dioxide (SO_2), PM_{10}, or carbon monoxide (CO)."

Proposed controlled emission levels to meet BAAQMD BACT requirements, from recent BAAQMD BACT determinations and the BAAQMD BACT Guidelines (BAAQMD 2005) can be found in the *Clean Fuels Project Application for Authority to Construct and Significant Revision to Major Facility* (ConocoPhillips 2006) and the *Hydrogen Plant Project Application for Authority to Construct and Major Facility Review Permit* (Air Liquide 2005).

Included in BAAQMD Regulation 2, Rule 2, are provisions that implement federal PSD requirements. USEPA policy includes a "top-down" BACT analysis for all pollutants emitted in PSD-significant quantities from new and modified emissions. As described in Section 3.0, PSD requirements apply to NO_x and PM_{10} in this proposed action. To supplement the BACT analysis presented in the above-referenced BAAQMD Authority to Construct (ATC) Applications, the remainder of this section presents "top-down" BACT analyses for the proposed new and modified sources of NO_x and $PM_{10,}$ based on the USEPA RACT/BACT/LAER Clearinghouse (RBLC), California Air Resources Board (CARB) BACT Clearinghouse, and available information on other recently issued permits.

USEPA guidance for a "top-down" BACT analysis requires reviewing all possible control options starting at the top level of control efficiency. In the course of the BACT analysis, one or more options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, or environmental impacts on a case-by-case (site-specific) basis. The steps required for a "top-down" BACT review are:

~~1.~~6. Identify All Available Control Technologies

~~2.~~7. Eliminate Technically Infeasible Options

~~3.~~8. Rank Remaining Technologies

~~4.~~9. Evaluate Remaining Technologies (in terms of economic, energy, and environmental impacts)

~~5.~~10. Select BACT (the most efficient technology that cannot be rejected for economic, energy, or environmental impact reasons is BACT)

4.1 U246 HEAVY GAS OIL (HGO) FEED HEATER

The proposed new U246 HGO Feed Heater supporting the modified Unit 240/246 Unicracker is proposed to be fired on refinery fuel gas (RFG), with natural gas as a backup fuel. The new HGO Feed Heater would be a natural draft process heater rated at 85 million British thermal units per hour (MMBtu/hr).

4.1.1 NO_x BACT – U246 HGO Feed Heater

1. Identify All Available Control Technologies

Table 3 lists the technologies identified for controlling NO_x emissions from process heaters fired on RFG or natural gas.

Table 3 NO_x Control Technologies

Control Technology
No Controls (Base Case)
Water/Steam Injection
Selective Non-Catalytic Reduction (SNCR)
Combustion Controls (Low-NO_X Burners)
Selective Catalytic Reduction (SCR)
Low-NO_X Burners and SNCR
Low-NO_X Burners and SCR
SCONOx

2. Eliminate Technically Infeasible Options

All the control methods identified in Table 3 are considered technically feasible for a process heater fired on RFG, except SCONOx™, SNCR, and water/steam injection.

SCONOx. SCONOx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO_x emissions. The catalyst oxidizes carbon monoxide (CO) to carbon dioxide (CO_2), and nitric oxide (NO) to NO_2. The CO_2 is exhausted while the NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is passed periodically across the surface of the catalyst to convert the KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2), thereby regenerating the K_2CO_3 coating for further absorption. The H_2O and N_2 are exhausted.

SCONOx has not been demonstrated on RFG-fired process heaters (Arizona Department of Environmental Quality [ADEQ] 2005). It has only been demonstrated on combustion sources burning exclusively natural gas. The performance of SCONOx is sensitive to sulfur in the exhaust stream. In addition, the heat ratings on natural gas burners demonstrated with SCONOx are lower than the proposed HGO Feed Heater. Thus, there are significant technical differences between the proposed source and those few sources where SCONOx has been demonstrated in practice. These preclude a finding that SCONOx has been demonstrated to function efficiently on sources identical or similar to the proposed process heater.

<u>Selective Non-Catalytic Reduction (SNCR)</u>. SNCR is a post-combustion NO_x control technology based on the reaction of urea or ammonia (NH_3) and NO_x. SNCR involves injecting urea/NH_3 into the combustion gas path to reduce the NO_x to nitrogen and water. This is described by the following chemical equations:

$$2\ CO(NH_2)_2\ (\textit{urea}) + 4\ NO + O_2 \rightarrow 4\ N_2 + 2\ CO_2 + 4\ H_2O$$
$$4\ CO(NH_2)_2 + 2\ NO_2 + 4\ O_2 \rightarrow 5\ N_2 + + 4\ CO_2 + 8\ H_2O$$

$$4\ NH_3\ (\textit{ammonia}) + 4\ NO + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$
$$4\ NH_3 + 2\ NO_2 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Temperatures ranging from 1,200°F to 2,000°F are required for optimum SNCR performance. Operation at temperatures below this range results in NH_3 slip, while operation above this temperature range results in oxidation of NH_3, forming additional NO_x. Exhaust temperatures of process heaters are typically below the optimum temperature range. In addition, the urea/ammonia must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO_x reduction.

SNCR can only be used in induced draft process heaters because of the need to recirculate the flue gas. The HGO Feed Heater will be a natural draft process heater. In addition, existing information on SCNR systems indicate they achieve NO_x reductions ranging from 30 to 75 percent (USEPA 2001), thus SNCR is an inferior control technology to either SCR or modern combustion controls for an RFG-fired process heater. Therefore, SNCR is considered infeasible for this review.

Water/Steam Injection. The injection of steam or water into the combustion zone can decrease peak flame temperatures, thus reducing thermal NO_x formation. Steam injection is predominantly used with gas turbines. There is little data available to document the effectiveness of water/steam injection for process heaters and no application of this type could be found. Steam injection has been specified as a control method for boilers on a very limited basis. Only one was listed in the USEPA RBLC database during the ADEQ's recent review of the Arizona Clean Fuels Yuma, LLC project (ADEQ 2005). This review showed a controlled emission rate higher than low NO_x burners produced today. Additionally, there are operating issues concerning flame stability using low NO_x burners with steam injection. Therefore, water/steam injection is considered infeasible for this review.

3. Rank Remaining Technologies

Technically feasible NO_x control technologies are listed in Table 4 with typical emission levels, ranked from most efficient to least efficient.

Combustion Controls. Combustion controls reduce NO_x emissions by controlling the combustion temperature or the availability of oxygen (O_2). These are referred to as "low NO_x burners" or "ultra-low NO_x burners." There are several designs of low/ultra-low NO_x burners currently available. These burners combine two NO_x reduction steps into one burner, typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment.

In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel-rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. This design is predominantly used with liquid fuels.

Table 4 NO_x Control Hierarchy for Process Heaters Fired on Refinery Fuel Gas

Technology	Typical Emission Level	
	ppmv[1]	**lb/MMBtu**[2]
Combustion Controls and SCR[3]	7	0.0085
Selective Catalytic Reduction (SCR)	18	0.022

Combustion Controls	29	0.035
No Controls[4]	89	0.11

Source: *Petroleum Refinery Tier 2 BACT Analysis Report*, *Final Report* (EPA, 2001).

[1] Parts per million by volume (ppmv), dry basis, corrected to 3% oxygen.

[2] Pounds (lbs) of NO_x produced per MMBtu of fuel heat input.

[3] Recent data show a range of values, with 7 ppmv representing the low end of current permitted levels on RFG-fired refinery heaters. See discussion of current BACT determinations in text for more details.

[4] Emission level shown is for a natural draft heater; an induced draft heater would typically have higher uncontrolled NO_x levels, on the order of 179 ppmv at 3% O_2, dry (USEPA 2001).

In staged fuel burners with IFGR, fuel pressure induces the IFGR, which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominantly used for gas fuel applications.

The range of performance achieved in practice for the best combustion controls is 25 to 29 ppmv at 3% O_2, dry (0.03 to 0.035 lb/MMBtu), with the upper end of range representing heaters firing gas with high hydrogen content (USEPA 2001). Burners that could achieve 10 ppmv or lower are under development, but are not currently available for process heaters.

RFG is high in hydrogen content, so for heaters burning RFG or a mixture of RFG and natural gas, the upper end of the demonstrated range (29 ppmv at 3% O_2, dry, or 0.035 lb/MMBtu) would be appropriate as the achievable performance level for combustion controls on RFG-fired process heaters.

Selective Catalytic Reduction (SCR). SCR is a process that involves post-combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging, ammonia slip emissions, and design of the NH_3 injection system. The most common catalysts are composed of vanadium, titanium, molybdenum, and zeolite. Sulfur dioxide and sulfur trioxide are generated in the flue gas when sulfur-containing compounds in fuel are combusted. Catalyst systems promote partial oxidation of sulfur dioxide (from sulfur and mercaptans in the fuel) to sulfur trioxide, which combines with water to form sulfuric acid, causing corrosion over time. In addition, sulfur trioxide and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled, which over time can accumulate on the catalyst causing “plugging” and catalyst deterioration, often referred to as “fouling.” These effects can be minimized by proper operation, including:

Controlling the amount of sulfur in the fuel.

Using a properly designed ammonia injection system to maximize the efficient mixing of ammonia and flue gas without colder surfaces present on which ammonium salts can condense.

Operating with the lowest amount of ammonia needed to achieve the desired performance. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which necessarily results in ammonia slip. Thus, an emissions tradeoff between NO_x and ammonia occurs in high NO_x reduction applications.

Operating at temperatures above the dew point of ammonium salts and sulfuric acid.
Optimal operating temperatures vary by catalyst but generally range from 500 to 800°F. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby adding NO_x emissions) or ammonium nitrate. Operating below the optimal temperature increases ammonia slip and catalyst fouling. Refinery process heaters typically operate in the range of 450 to 700°F, thus would be expected to operate above the dew point of ammonium salts and sulfuric acid to minimize fouling and corrosion. SCR systems have been used on process heaters burning mixtures of RFG and natural gas.
SCR systems achieve 80 to 90 percent reductions in NO_x emissions (USEPA 2001). The 90 percent reduction is relative to an uncontrolled induced draft heater since the higher NO_x emissions (approximately 179 ppmv at 3% O_2, dry, or 0.22 lb/MMBtu) versus a natural draft heater (approximately 89 ppmv at 3% O_2, dry, 0.11 lb/MMBtu) provides a greater driving force for increased mass transfer and also enhances the SCR’s mechanical draft requirements. This yields an outlet NO_x emission level of approximately 18 ppmv at 3% O_2, dry, or 0.011 lb/MMBtu. For a natural draft heater, maximum SCR control efficiency is on the order of 80 percent due to lower uncontrolled emission rates, yielding approximately the same controlled NO_x emission rate. Thus, a typical achievable performance level for SCR systems on RFG-fired process heaters is 18 ppmv at 3% O_2, dry, or 0.011 lb/MMBtu.
SCR and Combustion Controls. This control option uses SCR downstream of combustion controls to reduce NO_x emissions. With this combination, the inlet NO_x level to the SCR is lower, so lower outlet NO_x can be achieved. However, the SCR may not achieve the same percent reduction performance compared to

no upstream combustion controls because of the lower NO_x inlet levels. As is discussed further below, a review of the USEPA RBLC and CARB BACT Clearinghouse showed permit limits of 7 ppmv NO_x at 3% O_2, dry, as the lowest level achieved in practice on refinery process heaters with SCR and combustion controls fired on a combination of RFG and natural gas. Therefore, the achievable performance level for SCR and combustion controls on RFG-fired process heaters is 7 ppmv at 3% O_2, dry, or about 0.0085 lb/MMBtu.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, the top technically feasible control option, SCR with combustion controls, is the proposed control technology. Therefore, the selection of BACT consists of establishing the lowest controlled NO_x emission level achievable with this control technology, taking into consideration the lowest controlled NO_x emissions currently achieved in practice, and if necessary, energy, environmental and economic impacts between different potential controlled emission levels using this technology.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted. These reviews resulted in the lowest NO_x emission limits for refinery heaters fired on RFG/natural gas found in the South Coast Air Quality Management District (SCAQMD). A review of the BACT Determinations published by the SCAQMD provided further details.

There were three SCAQMD BACT Determinations for 7 ppmv NO_x at 3% O_2, dry, documented in the USEPA *Petroleum Refinery Tier 2 BACT Analysis Report* (USEPA 2001) for process heaters burning natural gas or a combination of RFG and natural gas. These were for: (1) Chevron El Segundo Refinery (Permit No. D64697, D62860, D64621); (2) TOSCO Refinery, Wilmington (Application 326118);[4] and (3) CENCO Refinery, Santa Fe Springs (Application 352869).

The ADEQ (2005) recently issued a permit for a similar project, Arizona Clean Fuels Yuma, LLC (ADEQ Permit Number 1001205). In their top-down BACT finding issued on 3 February 2005, the ADEQ summarized the following findings for the highest efficiencies achievable with SCR and combustion controls on RFG-fired process heaters (all 3-hour averages):

High-Efficiency SCR:

NO_x: 0.0085 lb/MMBtu (7 ppmv at 3% O_2, dry)[5]

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[4] Noted in the SCAQMD BACT Determinations to be for a 460-MMBtu/hr Hydrogen Reforming Furnace also combusting Pressure Swing Absorption (PSA) off gas.

[5] Although the NO_x permit limit for Arizona Clean Fuels Yuma LLC is presented as ppm corrected to 3% O_2, dry, the ADEQ Technical Report presents results in ppm corrected to

Moderate-Efficiency SCR:

NO_x: 0.0125 lb/MMBtu (10 ppmv at 3%O_2, dry)

The ADEQ concluded for Arizona Clean Fuels Yuma LLC that the beneficial environmental impacts of increased NO_x control for the high-efficiency SCR was outweighed by adverse environmental impacts of increased ammonia slip. Therefore, the NO_x emissions level found to be BACT was 10 ppmv at 3% O_2, dry.

The proposed NO_x emission limit for the ConocoPhillips HGO Feed Heater is 7 ppmv at 3% O_2, dry. This is equivalent to the high-efficiency SCR option that was ruled out by ADEQ, and matches the lowest NO_x emission limit achieved in practice. No further energy, environmental, or economic impact assessment is needed.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as SCR with combustion controls (low NO_x burners) at 7 ppmv at 3% O_2, dry, or 0.0086 lb/MMBtu.[6]

4.1.2 PM_{10} BACT – U246 HGO Feed Heater

1. Identify All Available Control Technologies

Table 5 lists the control technologies identified for controlling PM_{10} emissions from process heaters fired on natural gas or RFG.

Table 5 PM_{10} Control Technologies

Control Technology
Good Combustion Practice
Cyclone
Wet Gas Scrubber
Electrostatic Precipitator
Baghouse/Fabric Filters

Good Combustion Practice. By maintaining heaters in good working order and limiting the sulfur in the feed fuels, PM_{10} emissions are controlled.

Cyclone. A cyclone operates on the principle of centrifugal force. Exhaust gas enters tangentially at the top of the cyclone and spirals towards the bottom. As the gas spins, heavier particles hit the outside wall and are collected at the bottom. Cleaned gas escapes through an inner tube.

0% O_2, dry. These have been converted to 3% O_2, dry, for the purposes of the ConocoPhillips analysis.

[6] Slight difference from the previous conversions from 7 ppmv at 3% O_2, dry, due to fuel heat value assumptions and/or rounding.

Wet Gas Scrubber. A wet gas scrubber uses gas/liquid contacting to remove particles primarily by inertial impaction on liquid droplets, followed by collection of the larger liquid droplets as liquid waste.

Electrostatic Precipitator (ESP). An ESP uses an electric field to charge and collect particles in a gas stream, followed by collection of the particles on oppositely charged plates.

Baghouse/Fabric Filter. A baghouse is a metal housing containing many fabric bags. A partial vacuum pulls the dirty air through the fabric bags, filtering the particles from the exhaust stream.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM_{10} emissions from gas-fired heaters. The other technologies are not used because of inherently low PM_{10} emissions from gaseous fuel combustion. A cyclone would be ineffective in capturing the extremely small particles generated from gaseous fuel combustion, and costs associated with designing the other add-on systems to capture minute particles in low concentrations would be economically infeasible. This is a well-accepted finding of all past BACT determinations for the control of PM_{10} from combustion of gaseous fuels.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. Findings were the same as summarized by the ADEQ for the Arizona Clean Fuels Yuma LLC (ADEQ 2005). ADEQ proposed a PM_{10} emission limit of 0.0075 lb/MMBtu as representative of good combustion practice with gas-fired process heaters, based on the AP-42 emission factor (USEPA 1995a et seq.) for natural gas combustion and typical natural gas heat content. This is consistent with the lowest level achieved in practice.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM_{10} BACT is proposed as good combustion practice. The USEPA AP-42 natural gas combustion factor was adjusted with the estimated fuel heat content of the proposed RFG/natural gas mixture to calculate a proposed PM_{10} BACT emission level of
0.0057 lb/MMBtu.

4.2 HYDROGEN PLANT REFORMER Furnace

The proposed new Hydrogen Plant Steam Methane Reformer (SMR) Furnace is proposed to be fired on a mix of approximately 85 percent Pressure Swing Absorption (PSA) off gas and 15 percent RFG/natural gas.

4.2.1 NO_x BACT – Hydrogen Plant Reformer Furnace

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 3 of Section 4.1.1.

2. Eliminate Technically Infeasible Options

All the control methods identified in Table 3 are considered technically feasible for a Hydrogen Plant Reformer fired on the proposed mix of fuels, except SCONOx, SNCR, and water/steam injection, for the same reasons provided for a refinery process heater in Section 4.1.1.

3. Rank Remaining Technologies

Technically feasible NO_x control technologies are the same as listed in Table 4 of Section 4.1.1. Since the proposed mix of fuels includes natural and RFG, the emission levels presented in Table 4 can still be considered typical for this application. Inclusion of PSA off gas, however, affects combustion characteristics, and hence, can impact the actual achievable emission levels. Consideration of PSA off gas is included in the following BACT evaluation discussion.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, the top technically feasible control option, SCR with combustion controls, is the proposed control technology. Therefore, the selection of BACT consists of establishing the lowest controlled NO_x emission level achievable with this control technology, taking into consideration the lowest controlled NO_x emissions currently achieved in practice, and if necessary, energy, environmental and economic impacts between different potential controlled emission levels using this technology.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted. These reviews resulted in the lowest NO_x emission limits for hydrogen reformer furnaces fired on PSA off gas and RFG/natural gas found in the SCAQMD. A review of the SCAQMD BACT Determinations provided further details.

PSA off gas is high in hydrogen content, and therefore has the potential to form less NO_x and PM_{10}. There were five SCAQMD BACT Determinations for hydrogen reformer furnaces. In reverse chronological order, these NO_x emission limits were: (1) Chevron El Segundo Refinery (Application 411357, 5/19/2004, 5 ppmv at 3% O_2, dry); (2) Praxair, Ontario (Application 389926, 7/17/2002, 5 ppmv at 3% O_2, dry); (3) TOSCO Refinery, Wilmington (Application 326118, 9/9/1999, 7 ppmv at 3% O_2, dry); (4) Chevron El Segundo Refinery (Application 341340, 7/14/1999, 5 ppmv at 3% O_2, dry) and (5) Air Products and Chemicals, Inc. (Application 337979, 6/16/1999, 5 ppmv at 3% O_2, dry).

The proposed NO_x emission limit for the Air Liquide Hydrogen Reformer is 5 ppmv at 3% O_2, dry. Since this is the lowest NO_x emission limit achieved in practice, no further energy, environmental, or economic impact assessment is needed.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as SCR with combustion controls (low NO_x burners) at 5 ppmv at 3% O_2, dry, or 0.0058 lb/MMBtu.

4.2.2 PM_{10} BACT – Hydrogen Plant Reformer Furnace

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 5 of Section 4.1.2.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM_{10} emissions from gas-fired heaters, as described in Section 4.1.2.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. No applicable PM_{10} BACT emission levels were found. The five SCAQMD BACT Determinations for hydrogen reformer furnaces did not include PM_{10}, thus, from Section 4.1.2, a PM_{10} emission limit of 0.0075 lb/MMBtu is representative of good combustion practice with gas-fired process heaters. In this case, the proposed Hydrogen Reformer will fire up to 85 percent PSA off gas, which produces less PM_{10} emissions due to high hydrogen content. It is proposed that with the inclusion of PSA off gas, a reasonable PM_{10} emission limit would be half the amount produced by natural gas alone, or 0.0037 lb/MMBtu.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM_{10} BACT is proposed as good combustion practice at 0.0037 lb/MMBtu. The proposed PM_{10} emissions level is consistent with the lowest level achieved in practice, with further consideration given for the PSA off gas in the fuel mixture.

4.3 SULFUR RECOVERY UNIT (SRU)

The proposed new Unit 235 SRU will be a closed Claus process supported by an amine-based TGTU to convert unreacted hydrogen sulfide (H_2S) from the Claus process. The TGTU is also a closed process. Any unreacted H_2S in the tail gas passing through the TGTU will be oxidized in a new tail gas incinerator, which is the emission point for the process. Vents from the new sulfur loading rack will also be routed to the tail gas incinerator for oxidation of H_2S. Therefore, BACT for the SRU was assessed for NO_x and PM_{10} from the tail gas incinerator.

4.3.1 NO_x BACT – SRU Tail Gas Incinerator

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 3 of Section 4.1.1.

2. Eliminate Technically Infeasible Options

The only option listed in Table 3 that is technically feasible for an SRU tail gas incinerator is combustion control with low-NOx burners. The other technologies are either based on lowering flame temperature, which is not compatible with the primary function of the incinerator (i.e., efficient oxidation of reduced sulfur compounds), or add-on controls that have not been demonstrated technically feasible for a thermal oxidizer. There are significant technical differences between thermal oxidizers and the combustion sources for which these technologies have been demonstrated in practice.

3. Rank Remaining Technologies

The only technically feasible NO_x control technology is combustion control with low-NOx burners.

4. Evaluate Remaining Technologies

Technically feasible technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated until it cannot be ruled out for energy, environmental, or economic reasons.

In this case, a review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for the most efficient low-NOx burners achieved in practice for tail gas thermal oxidizers for SRU TGTUs. These reviews resulted in the lowest NO_x emission limit achieved in practice as 42.2 ppmv @ 7% O_2, dry, or 0.0667 lb/MMBtu, associated with the recently issued PSD permit for the SRU TGTU at the ConocoPhillips Ferndale Refinery. This level, for a unit currently in operation, is similar to the 0.06 lb/MMBtu level proposed by the ADEQ for the Arizona Clean Fuels Yuma LLC (ADEQ 2005), a facility not yet in operation.

5. Select BACT/ Document the Selection is BACT

Based on this review, NO_x BACT is proposed as combustion control with low-NOx burners at 42.2 ppmv at 7% O_2, dry, or 0.0667 lb/MMBtu.

4.3.2 PM_{10} BACT – SRU Tail Gas Incinerator

1. Identify All Available Control Technologies

The available technologies are the same as listed in Table 5 of Section 4.1.2.

2. Eliminate Technically Infeasible Options

All options in Table 5 are technically feasible.

3. Rank Remaining Technologies

See next (Step 4) discussion.

4. Evaluate Remaining Technologies

While the listed control technologies are all technically feasible, only good combustion practice is used for controlling PM_{10} emissions from the combustion of gaseous fuels, as described in Section 4.1.2.

A review of the USEPA RLBC and CARB BACT Clearinghouse was conducted for currently achieved control levels. No applicable PM_{10} BACT emission levels were found. It is proposed that reasonable PM_{10} emission limit would be the amount produced by natural gas alone, or 0.0075 lb/MMBtu.

5. Select BACT/ Document the Selection is BACT

Based on this review, PM_{10} BACT is proposed as good combustion practice at 0.0075 lb/MMBtu. The proposed PM_{10} emissions level is consistent with the lowest level achieved in practice.

4.4 New Flaring

The proposed project includes a new Hydrogen Plant flare that would operate during planned and unplanned events. The shutdown and startup of the new Unit 240/246 would also cause new flaring emissions from the existing Main Flare, but this is estimated to occur only once every three years.

Flares operate primarily as air pollution control devices, but are nonetheless emission sources subject to BACT analyses. The technically feasible control options for emissions of all pollutants from flares are equipment design specifications and work practices: minimizing exit velocity, ensuring adequate heat value of combusted gases, and minimizing the quantity of gases combusted. Each of these control options is technically feasible and is required for the operation of emergency flares at the refinery.

The equipment design criteria for emergency flares are based largely on the parallel requirements set forth in the NSPS regulations (40 CFR 60.18) and the National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations (40 CFR 63.11). These include a maximum allowable exit velocity, a requirement for smokeless operation, and a minimum allowable net heating value for gases combusted in the flares. ConocoPhillips is not aware of any more stringent requirements imposed on flares at any other petroleum refinery, nor any other technically feasible control options for emissions of any pollutants from flares.

Appendix C

CEQA FINDINGS

CONOCOPHILLIPS – SAN FRANCISCO REFINERY
PROPOSED CLEAN FUELS EXPANSION PROJECT

FINDINGS AND SUPPORTING FACTS REGARDING THE ENVIRONMENTAL IMPACT REPORT

ConocoPhillips - San Francisco Refinery (The Refinery) has proposed to construct the Clean Fuels Expansion Project (CFEP) at its Rodeo Refinery. The CFEP includes new equipment and modifications to existing equipment that would enable the Refinery to process heavy gas oil (HGO), which is a by-product that is currently produced onsite and exported. Implementation of the CFEP would allow overall Refinery production to increase by up to 1,000,000 gallons per day (30 percent over current levels).

The CFEP includes the following: (1) construction of a new Hydrogen Plant to be built by Air Liquide with a capacity of 120 million standard cubic feet per day; (2) construction of a new Sulfur Recovery Unit with a capacity increase of 200 long tons per day; (3) conversion of a retired lube oil rail car loading rack into a butane rail car loading rack; (4) expansion of the Unicracker to allow for HGO hydrocracking and resulting in an increase in capacity of 23,000 barrels per day (bbl/day); (5) Reformer (Unit 244) modifications resulting in a capacity increase from 16,087 bbl/day to 18,500 bbl/day; (6) UNISAR (Unit 248) modifications resulting in a capacity increase from 8,812 bbl/day to 16,740 bbl/day; (7) Product Blending Unit (Unit 76) modifications resulting in a capacity increase from 90,411 bbl/day to 113,150 bbl/day; (8) Deisobutanizer (Unit 215 DIB) modifications resulting in a capacity increase from 7,600 bbl/day to 10,200 bbl/day; (9) Sulfur Recovery Plant (Units 234, 236, 238) modifications that would include a new sulfur degassing system, a new sulfur loading rack, a modified or replaced amine regenerator and an increase in sulfur storage capacity; and (10) modifications to ancillary facilities such as pumps, heat exchangers, instrumentation, utilities and piping.

Contra Costa County Community Development Department (CDD) acted as Lead Agency under the California Environmental Quality Act (CEQA) for this project. As a responsible agency under CEQA, the Bay Area Air Quality Management District (BAAQMD) participated in the EIR process, including reviewing and commenting on the Draft EIR. The following timeline illustrates the land use permit application's progress from approval by County Planning Commission (CPC) to present:

- April 24, 2007 – Public hearing held before the CDD in Martinez to consider certification of the Final EIR and approval of the CFEP.

- May 8, 2007 – Second CPC hearing held in Martinez. Final EIR was certified and project was approved with new and modified Conditions of Approval.

- May 17, 2007 – Appeal received from Communities for a Better Environment and Center for Biological Diversity (CBE/CBD), joint appellants.

- May 18, 2007 – Appeal received from ConocoPhillips Company and appeal received from the California State Attorney General.

- September 10, 2007 – California Attorney General withdrew his May 18, 2007 appeal and submits a copy of Settlement Agreement with ConocoPhillips Company. Concurrently, ConocoPhillips requests that the County include language from the Settlement Agreement in the County's action on its appeal.

- September 25, 2007 – Board of Supervisors hearing held in Martinez. Final EIR was certified and project was approved. Board accepted the September 10, 2007 letter from the California Attorney General withdrawing their May 18, 2007 appeal. The Board denied the appeals of Communities for a Better Environment (CBE) and Center for Biological Diversity (CBD). The Board also granted the appeal of ConocoPhillips Company based on their revised proposed condition of approval addressing the storage of rail cars.

The EIR identified certain potentially significant environmental impacts that could occur as a result of the CFEP. The following discussion summarizes the air quality related effects identified in the EIR and during the District's review of the ConocoPhillips and Air Liquide permit applications, makes one or more of the findings required under Section 15091 of the State CEQA Guidelines, and presents facts to support the findings. All of these effects have been mitigated to a level of insignificance.

Impact 1 – Construction activities associated with CFEP would generate short-term emissions of criteria pollutants, including suspended and respirable particulate matter and equipment exhaust emissions, which would contribute to existing air quality violations.

Mitigated to insignificance. Particulate emissions will be mitigated by implementation of comprehensive dust control measures including watering all active construction areas at least twice daily; covering of haul trucks or requiring all trucks to maintain at least two feet of freeboard; paving or otherwise stabilizing haul roads, parking and staging areas; and sweeping daily with water sweepers all paved access roads, parking areas and staging areas at construction sites. The following "enhanced" control measures will also be implemented: Hydroseeding or application of non-toxic soil stabilizers to inactive construction areas; enclosing, covering, watering twice daily or application of non-toxic soil binders to exposed stockpiles; installation of sandbags or other erosion control measures to prevent silt runoff to public roadways; suspension of excavation and grading activity when winds exceed 25 mph; installation of wheel washers for all exiting trucks, or washing off the tires or tracks of all trucks and equipment leaving the site.

Equipment emissions will be mitigated by regular equipment maintenance and limits to unnecessary idling. Other equipment mitigation measures include the following: use of alternative fuels and/or alternatively fueled equipment; use of post-1996 model diesel trucks only at the site or for on-road hauling of construction material; requirement for all construction diesel engines with a rating of 100 hp or more to meet at a minimum the Tier 2 California Emission Standards for Off-Road Compression –Ignition Engines unless certified by the onsite Construction Air Quality Mitigation Manager (CAQMM) that such an engine is not available for a particular item of equipment; offering incentives to encourage construction workers to carpool or employ other means of transportation; scheduling construction activities to allow at least 33% of the construction workforce to avoid the morning and afternoon peak traffic periods; and use of on-site power to minimize reliance on portable generators.

Impact 2 – Operational activities associated with the implementation of the CFEP would increase air pollutant emissions, contributing to existing air quality violations.

Mitigated to insignificance. As required by BAAQMD Rules and Regulations, project emissions will be mitigated by application of Best Available Control Technology (BACT) and by obtaining emission offsets. Specifically, following mitigation measures will be implemented:

- The four Dissolved Air Flotation (DAF) vents associated with the onsite wastewater treatment plant will be routed to a Thermal Oxidizer with a destruction efficiency of no less than 98 percent. The DAF outlet channel and downstream sumps will be sealed by a solid cover with gaskets. Any vents installed on the covered channel will be routed to the thermal oxidizer. Installation of these controls will reduce organic emissions by at least 242 pounds per day and 44.1 tons per year.

- The Refinery Steam Power Plant uses three gas turbines to generate electricity, and uses gas turbine waste heat to generate steam. Each gas turbine has a nitrogen oxide (NOx) catalyst system located at the base of the exhaust stack. The Refinery will take a new permit limit to achieve a reduction of NOx concentration in each stack by 1 ppm from its current operating baseline. This 1 ppm of NOx equates to a reduction of 81 pounds per day and 14.7 tons per year.

- Operations at the ConocoPhillips' Carbon Plant will be modified to result in a decrease in SO2 emissions of at least 230 pounds per day and 42 tons per year. The refinery will take a new permit limit to reflect this reduction.

- The baghouse at the Carbon Plant will use improved bag technology to capture particulate matter (PM_{10}) from the calcined coke operation. Installation of the improved bag-technology will reduce PM_{10} emissions by at least 43.8 pounds per day and 8.0 tons per year. The refinery will take a new permit limit to reflect this reduction.

- Net reductions in ROG emissions associated with the mitigated CFEP will be used to offset 36 pounds per day and 7.6 tons per year of NOx associated with the CFEP.

Impact 3 – The CFEP would contribute to cumulative regional air emissions; however, it would not be cumulatively considerable and it would not conflict with or obstruct implementation of the applicable air quality plan.

Mitigated to insignificance. As discussed in Impact 2, with the proposed mitigation measures, the CFEP would have a less-than-significant impact on air quality. Furthermore, as discussed in Section 4.10, Land Use, in Final EIR, the CFEP is consistent with the Contra Costa County General Plan which in turn is consistent with the BAAQMD's current air quality plan (2005 Ozone Strategy).

Impact 4 – Operational activities associated with the implementation of the CFEP could lead to increases in odorous emissions. This would be a less-than-significant impact.

No mitigation required. The CFEP will not result in increased odors because the hydrocracking process that would be used to process heavy gas oil produces clean intermediate feedstocks and blendstocks. Storing these products in existing tanks will not increase odors. Also, CFEP contains numerous design features that will reduce odor emissions from existing equipment and minimize the likelihood of odor emissions from the project's new equipment. CFEP-related design features include the following:

- A fourth compressor will be added to the odor abatement system. This will increase the robustness of the odor control system. The new compressor will be sized at approximately 3.3 MMSCFD and is slated to commence operation in March 2009.

- The new compressor will primarily be loaded with odor abatement gases but will be operated so that during most periods, it can pick up the swings that occur during brief peak loading on the existing G-503, Flare Gas Recovery (FGR) compressor. This new compressor will also be used to mitigate flaring when the G-503 FGR compressor is down for planned or emergency maintenance. This additional flare gas recovery capacity will further reduce odor-causing flaring.

- The vapor recovery will be installed on existing fixed-roof tanks that will change service to store heavy gas oil and sour water.

- The Odor abatement system will be subject to new and more stringent permit conditions by the BAAQMD to eliminate and/or minimize odor complaints.

- A new sulfur recovery unit will increase system redundancy and improve the refinery's ability to react to upset conditions for processing sulfur gases. This will reduce the number of refinery upsets and shutdowns.

- Molten sulfur loaded into trucks will be degassed prior to loading, which will reduce the H_2S emissions.

- The Dissolved Air Flotation unit at the wastewater treatment plant will be vented to a thermal oxidizer.

- After startup of the CFEP, less heavy gas oil will be loaded onto barges, which vent to the atmosphere.

As required by the State CEQA Guidelines, the BAAQMD, as a Responsible Agency for the ConocoPhillips CFEP, hereby finds that, for each of the impacts identified in the final EIR and discussed above, changes or alterations have been required in, or incorporated into, the project which avoid or substantially lessen the significant environmental effect as identified in the final EIR. In addition, for those mitigation measures that are identified in the final EIR to lessen impacts associated with construction activities and vehicle emissions and that are within the responsibility or jurisdiction of another public agency, the BAAQMD hereby finds that such measures either have been or can and should be adopted by such other agency.

In accordance with BAAQMD Rules and Regulations, the BAAQMD has fully considered the EIR prepared and certified by the Contra Costa County and has incorporated the EIR's analysis into its decision-making process. The BAAQMD granted an Authority to Construct for the proposed project on October 5, 2007.

The documents and other materials that constitute the record of proceedings upon which this decisions is based are located at the BAAQMD office at 939 Ellis Street, San Francisco, California, and the custodian of the materials is Rochelle Henderson.

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Jack P. Broadbent
Executive Officer/Air Pollution Control Officer
Bay Area Air Quality Management District