Bay Area Air Quality Management District

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~~Draft~~
Permit Evaluation
and
Statement of Basis
for
MAJOR FACILITY REVIEW PERMIT
Reopening – Revision 1

for

Valero Refining Co. - California
Facility #B2626

Facility Address:
3400 East Second Street
Benicia, CA 94510-1097

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~~February~~**August**, 2004

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Title V Statement of Basis

A. Background

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

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

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

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

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

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

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

There is no significant increase in facility emissions due to the revisions in this permit. The majority of the changes are corrections and clarifications. Details of the significant (i.e. more than just typos or extraneous text changes) permit changes are listed in Section G of this document. The two major permit conditions that were added (Flare and NOx Box, covered in more detail in Section C.IV), cover details of source monitoring and do not, in themselves, result in any change in emissions. The new District permit applications incorporated into the permit since the December 1, 2003 permit are shown below:

Application Number(s)	Description
2035	MTBE Phaseout
3782	Alkylation Expansion
8028 and 8247	Spare Tail Gas Unit for Sulfur Plants

The spare tail gas unit A-64 is an identical backup for the existing A-24 and normally only one unit will be operating at a time. There will be short periods when both units are simultaneously operated when switching units. Assuming this will occur no more than 5 times per year, it is estimated that the emissions will increase as follows: POC, 0.00032 ton/yr; NOx, 0.006 ton/yr; SO2, 0.000036 ton/yr; PM10, 0.004 ton/yr; and CO, 0.005 ton/yr. For the remaining two applications, the total POC emissions increase 0.745 tons/yr. These emissions were offset as required by Regulation 2-2-302.

B. Facility Description

General Description of an Oil Refinery:

An oil refinery is an intermediary between crude oil and a refined product. It takes dirty, low-value oil from the ground and distills it under atmospheric pressure into its primary components: gases (light ends), gasolines, kerosene and diesels (middle distillates), heavy distillates, and heavy bottoms. The heavy bottoms go on to a vacuum distillation unit to be distilled again, this time under a vacuum, to salvage any light ends or middle distillates that did not get separated under atmospheric pressure; the heaviest bottoms continue on to a coker or an asphalt plant.

Other product components are processed by downstream units to be cleaned (hydrotreated), cracked (catalytic or hydrocracking), reformed (catalytic reforming), or alkylated (alkylation) to form gasolines and high-octane blending components, or to have sulfur or other impurities removed to make over-the-road diesel (low sulfur) or off-road diesel (higher sulfur). Depending on the process units in a refinery and the crude oil input, an oil refinery can produce a wide range of salable products: many different grades of gasoline and gasoline blend stocks, several grades of diesel, kerosene, jet and aviation fuel, fuel oil, bunker fuels, waxes, solvents, sulfur, coke, asphalt, or chemical plant feedstocks.

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

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

The principal sources of air emissions from refineries are:

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

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

Valero Refining – Benicia Fast Facts

-- Produces 10 percent of the clean-burning California Air Resources Board (CARB) gasoline used in California and 25 percent of the CARB used in the San Francisco Bay Area.

-- Total feedstock throughput capacity of 180,000 barrels per day (BPD)

-- Products include CARB gasoline, diesel, jet fuel, fuel oil, residual oil and asphalt

Overview

Built as a grass-roots project in 1969, the Benicia refinery has undergone significant modifications and upgrades over the years. Valero acquired the facility in 2000.

Output

This facility has the ability to process sour crude oils into a high percentage of light products. Approximately 70 percent of the refinery's product slate is CARB gasoline – California's clean-burning fuel. The refinery also has significant asphalt production capabilities and produces 25 percent of the asphalt supply in northern California. Currently, it processes domestic crude both from the San Joaquin Valley (SJV) in California and from the Alaska North Slope (ANS). Major refinery units include:

-- 135,000-BPD crude distillation unit

-- 77,000-BPD fluid catalytic cracking (FCC) unit

-- 39,500-BPD coker unit
-- 40,000-BPD hydrocracker
-- 40,000-BPD catalytic reformer

C. Permit Content

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

The standard conditions also contain references to BAAQMD Regulation 1 and Regulation 2. These are the District's General Provisions and Permitting rules.

Condition I.J has been added to clarify that the capacity limits shown in Table II-A are enforceable limits.

II. Equipment

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

Permitted sources are those sources that require a BAAQMD operating permit pursuant to BAAQMD Rule 2-1-302. The Permitted sources are shown in the Permit Table II A.

The exempt sources may or may not have a source number. The exempt sources are shown in the Permit Table II B.

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 or A-24). This abatement equipment is shown in the Permit Table II C. If a source is also an abatement device, such as when an engine controls VOC emissions, it will be listed in the abatement device table but will have an "S" number. An abatement device may also be a source (such as a thermal oxidizer that burns fuel) of secondary emissions. If the primary function of a device is to control emissions, it is considered an abatement (or "A") device. If the primary function of a device is a non-control function, the device is considered to be a source (or "S").

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.

There are no equipment differences between the Final Permit issued December 1, 2003 and this version. There are some minor discrepancies that were corrected. These include:

- S-211 was reinstated in the Permitted Sources Table II A. This source was originally the MTBE Plant that was taken out of service in 2003. However, the main unit tower is now used as an Alkylate Debutanizer so S-211 was returned to Table II A to cover this source.

- The Claus Units abatement system was corrected in Table II C. This system consists of A-24, The Tail Gas Hydrogenation Unit, followed by A-56, the Flexsorb Process. Applications 8028 and 8427 for a spare tail gas unit were granted a Permit to Operate in late 2003. This spare unit was designated A-62 in error (A-62 is already the SCR unit of S-1032 and S-1033). Therefore, a correction was made to show A-64, the Spare Tail Gas Hydrogenation Unit.

The District permit applications not included in this proposed permit are as follows:

- Application 5846: Valero Improvement Project. This Application was granted an Authority to Construct in July 2003.
- **Application 7980: Transfer of Selected Storage Tank assets to Valero Logistic Operations Facility B5574.**

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.

IV. Source-Specific Applicable Requirements

General Information

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. ~~At the top of each set of permit conditions applicable to a source(s) in Table IV, Valero has also included a unique environmental file number, shown as either 8.1.XXX or 8.2.XXX. Valero's environmental file number cross-references the District's Condition ID# for these same permit conditions, in order to track and facilitate compliance.~~

Complex Permit Issues and Applicability Determinations

Combustion Sources Under Alternative Compliance Plan:

<u>Sources S-7, S-20, S-21, S-22, S-23, S-24, S-25, S-26, S-30 through S-33, S-34, S-35, S-40, S-41, S-173 and S-220</u>

The above listed sources are combustion sources that are subject to Regulation 9, Rule 10, because they are located at a refinery and have a rated heat input that is more than 10 MMBTU/hr. Regulation 9 Rule 10 limits nitrogen oxide (NOx) and carbon monoxide (CO) emissions from boilers, steam generators and process heaters at refineries. Effective July 1, 2002, refineries became subject to the emission standard of 0.033 pounds of NOx per million BTU of heat input, averaged over all affected units each day. This NOx standard is contained in Section 9-10-301. This is the primary standard in this rule. Section 9-10-305 limits CO emissions to 400 ppmv (dry, 3% O_2). Because of the inverse relationship between NOx and CO emissions, this CO limit is included in the rule to ensure that CO emissions do not significantly increase because of NOx control efforts. Section 9-10-304 contains a separate NOx limit for CO Boilers of 150 ppm (dry, 3% O_2), or an abatement system with an efficiency of at least 50%.

Prior to the effective date of Regulation 9, Rule 10, each refinery was required to submit a *Control Plan* and a *Monitoring Plan* outlining how the refinery would comply with Regulation 9, Rule 10. The Control Plan includes: a list of all affected units, a description of the NOx control system for each affected unit, the projected NOx emission rate for each unit, and an implementation schedule for the installation of additional control equipment. The Monitoring Plan includes: a list of sources to be equipped with NOx, CO and oxygen continuous emission monitors (CEMs), a list of sources for which an equivalent verification system would be used, and a description of fuel flow meters for each source or group of sources.

Compliance with Regulation 9, Rule 10 is determined daily. The owner/operator uses a combination of CEM data, unit-specific NOx emissions factors, fuel usage and fuel heat content data to calculate the daily average NOx emissions per unit of heat input (lb NOx / million BTU) for the affected sources. Compliance with the CO Boiler NOx concentration limit is determined directly by CEM. Compliance with the CO concentration limit is determined by either CEM or periodic source tests.

Not all sources are monitoring by CEMs. In general, emissions from large units are measured with CEMs and emissions from small units may be determined using an equivalent verification system. The District determines equivalency for this purpose on a case-by-case basis, guided by the District policy entitled "*NOx, CO and O_2 Monitoring Compliance with Regulation 9, Rule 10*", signed by Bill De Boisblanc, June 23, 2000, and amended April 10, 2003. This policy states that in lieu of CEMs, the owner/operator may establish a pre-defined operating range (often referred to the "NOx Box", which is address below), for smaller sources (less than 200 MMBtu/hr rating), based on a series of source tests. Emissions for such sources are calculated based on source-specific emission factors and measured fuel usage. The pre-defined operating ranges are specified in BAAQMD Permit Condition # 21233.

The owner/operator is required to retain records of data necessary to determine compliance for a period of at least five years, and to submit written quarterly reports to the District.

This refinery also uses Interchangeable Emission Reductions Credits (IERCs) as a means of complying with the refinery-wide average NOx limit in Section 9-10-301. The daily average NOx emission rate (lb NOx/million BTU) is determined as described above. If this emission rate exceeds the limit of 0.033 lb/million BTU, the refinery must use sufficient IERCs to offset the difference between the actual emission rate and the Regulation 9, Rule 10 limit, plus ten percent of the difference. IERCs are generated in accordance with Regulation 2, Rule 9, by early compliance or over-compliance with an emission standard. IERCs must be formally banked prior to use, and can only be used as part of an Alternative Compliance Plan (ACP) approved under Regulation 2-9. At the end of each ACP year, the refinery surrenders the IERC banking certificates sufficient to cover the IERCs that were consumed during the prior ACP period.

In the case of Valero Refinery, Sources at Facility B3193 (S19, S20, S21) are considered together with the sources that are subject to Regulation 9-10-301 at Facility B2626, Valero Refining. Valero intends to comply with Regulation 9-10-301 by using IERCs that the facility generates by over-controlling its CO Boilers. Valero applied for these IERCs in Application 3915. The evaluation for Application 3915 is attached in Appendix A. Condition 19329 concerning the IERCs has been added to the Section IV and VII tables. Valero has continued to apply for additional IERC's as the credits are generated.

NOx Box

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

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

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

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

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

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

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

<u>Federal Enforceability</u>

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

<u>Changes from the current conditions</u>

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

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

The changes can be summarized as follows:

- The old policy allowed for operation at conditions outside the perimeter of test conditions. The reason for this was to account for the fact that requiring the facility to test the furnace at specific conditions could have an expensive impact on production. While this is still true, there was also considerable opportunity for circumvention, where a facility could have sustained operation outside the box, and then test at conditions that happened to be well within the box. The new policy requires that a test be conducted that would capture the new conditions. The impact on process operation is mitigated by allowing the facility to delay testing until the next periodic source test.
- The old policy used one emission factor for all allowable operating conditions. The new policy allows two boxes, with two factors. One lower factor applies to routine operating

conditions, while another higher factor may be used for normal operation at higher levels. This provides more flexibility without sacrificing the assurance of compliance.

- The NOx box can be a 5-sided polygon, rather than a simple box.
- Because the policy is, in some ways, more stringent, time to conduct the source tests to establish the new boxes has been allowed. Existing NOx Box conditions will remain in effect until June 1, 2004, when they will be replaced by the new conditions.
- Under the old policy, two Notices of Violations (NOVs) issued because of a single source would automatically trigger a requirement to install a NOx CEM. Under the new policy, two NOVs will trigger a review by District staff to determine if the NOx Box for that source is still deemed equivalent to a NOx CEM. If it is not, a NOx CEM will be required.
- The new policy allows a facility to operate at low firing rates (idling) for a limited period of time, without having to expand the box to include those conditions. There are two reasons for this. First, emissions at low fire are much lower than normal, even if the emission factor is higher. Second, it is an extreme hardship to require the facility to turn down its production in order to test at very low fire conditions.

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

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

Part 2 requires installation of oxygen monitors **for units with a maximum firing rate greater than 25 MMBtu/hr**. This is necessary because some of the smaller heaters are not required by Regulation 9-10 to have oxygen monitors. Oxygen content must be monitored continuously to demonstrate compliance with the condition. Operators will be allowed six months to install any newly-required oxygen monitors.

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

Part 3B covers small units (<25MMBtu/hr). The NOx Box for small units is essentially the entire potential operating range for the unit. Rather than establishing the “corners” of the box, the box is defined to be the full range of firing rates, and all possible oxygen contents. **The potential operating range was defined as 20% to 100% of maximum rated capacity. However, for S-35, the minimum operating level is 8% in this service.** Existing data may be used to establish the emission factor that will be applied. Unless the unit is fired above its rated capacity, it is not possible to operate outside the box. An annual source test will confirm that the factor used is still valid.

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

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

Part 5 describes the actual NOx box.

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

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

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

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

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

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

District will evaluate each situation case by case, and will use its authorities to require installation of a CEM where appropriate.

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

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

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

Small furnaces are tested once per year. Large furnaces are tested every six months. **Both sizes have allowable delays for a unit that is experiencing an extended shutdown, requiring a source test within 30 days of startup.**

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

Part 9 requires installation of a CO CEM **on units larger than 25 MMBtu/hr** if two sources tests show CO levels greater than 200 ppm. Normal CO concentrations are an order of magnitude lower. One high CO reading is an anomaly. Two high readings are an indication that CO may be a problem, and continuous monitoring of firing rate and O2 is not equivalent to continuous monitoring for CO.

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

Flares S-16, S-17, S-18 and S-19

The Benicia Refinery has three separate flare header systems: 1) the main flare gas recovery header with flares S-18 and S-19, 2) the acid gas flare header with flare S-16, and 3) the butane flare header with flare S-17. Flares S-16 and S-18 were placed in service during the original refinery startup in 1968. Flare S-17 was placed in service with the butane tank TK-1726 in 1972. Flare S-19 was added to the main gas recovery header in 1974 to ensure adequate relief capacity for the refinery. S-19 is subject to NSPS Subpart J, because it was a fuel gas combustion device installed after June 11, 1973, the effective date of 60.100(b).

S-16, the Acid Gas Flare ST-2101AG serves the Claus Sulfur Recovery Units S-1 and S-2 and is only used during emergency malfunctions in those units. S-17, the Butane Flare ST-1701 serves the Butane Tank TK-1726. The off gas from this tank is recovered by a vapor recovery refrigeration system. To the extent the S-17 Butane Flare only operates as backup during an emergency malfunction of this vapor recovery system, it is exempt from the H_2S limit of NSPS Subpart J.

S-18, the South Flare ST-2101, and S-19, the North Flare ST-2103, are part of the main refinery flare gas recovery header system. Any gas that flows into the main refinery flare gas recovery system is first abated by the Vapor Recovery Compressor A-13 and/or A-26 and routed to the refinery fuel gas system. Normally all the vapors are collected by A-13 and/or A-26 and there is no flow to S-18 and S-19. In the event that the gas flow to the main refinery flare gas recovery system exceeds the capacity of the Vapor Recovery Compressor, or if neither compressor is operating, the pressure in the flare header will reach a level where the water seal in the knockout drum to S-18 is broken and gas will be flared at S-18. If the pressure continues to build in the flare header, the water seal in the knockout drum to S-19 will also be broken and gas will be flared at S-19.

An overview of the flares and thermal oxidizers, including a summary of applicable requirements, is provided on a later page of this section. Specific applicability determinations follow.

Applicability Determination of 40 CFR Part 60 Subpart J to A-57 Thermal Oxidizer

The Valero Benicia Refinery has one thermal oxidizer (A-57) at the Wastewater Treatment Plant (WWTP), which abates VOC emissions from tanks and primary separation equipment.

There was considerable dialogue between the District and the Owner/Operator of A-57 regarding the applicability of Subpart J. Since the Draft Permit was issued, two plausible (and conflicting) applicability determinations have been developed and discussed. The Proposed Permit does not include Subpart J as an applicable requirement for Thermal Oxidizer A-57, consistent with the Draft permit released for public comment. A summary of the two applicability determinations follows.

Subpart J Does Apply:

The operation of A-57 is flameless, using electrical power to heat a ceramic bed to high temperatures. A-57 is a relatively new abatement device designed as a partner to A-37, the WWTP Carbon Adsorption abatement. When the waste gas is directed to A-57, the organic content is abated by high temperature oxidation. The definition of Fuel Gas Combustion Device in 60.101(g) does not specifically include (nor exclude) thermal oxidizers. Furthermore, 60.101 does not include a definition of 'combustion'. However, using the Merriam-Webster Dictionary definition – "a usually rapid chemical process (as oxidation) that produces heat and usually light" – then the flameless thermal oxidation in A-57 can be considered combustion. In addition, using the broadest interpretation of the definition of Fuel Gas in 60.101(d), the WWTP emissions are "fuel gas" regardless of origin, quantity or quality. As a result, Subpart J should be an applicable requirement for A-57.

Subpart J Does Not Apply:

60.100(a) specifies that the provisions of Subpart J apply to affected facilities at petroleum refineries, including fuel gas combustion devices. 60.100(b) further specifies that fuel gas combustion devices constructed or modified after June 11, 1973 are subject to Subpart J. 60.101 indicates that definitions not provided in Subpart J have the meaning given to them in the CAA and in Subpart A. Therefore, definitions provided in Subpart J, such as petroleum refinery, supersede any definitions that may be available elsewhere in the CAA and Subpart A. The following relevant definitions are included in Subpart J (definitions listed out of order for emphasis):

> **(g) "Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas,…"**
> **(d) "Fuel gas means any gas which is generated at a petroleum refinery and which is combusted…" (Note that the fuel gas must be generated at a petroleum refinery, as defined herein.)**
> **(a) "Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives." (Petroleum refinery is narrowly defined, limited to specific processing facilities, and does not include references to storage vessels or ancillary operations, such as the WWTP. In addition, the definition of a petroleum refinery does not include phrases like "such as" or "for example" which might otherwise expand or generalize the scope of this definition. In contrast, other definitions such as petroleum refining process units in 40 CFR Part 63 Subpart CC include storage vessels and treating processes, such as wastewater treatment plants, for applicability, and therefore are more comprehensive in scope than the definition of petroleum refinery included in Subpart J.)**

The processing facilities specified in this definition of petroleum refinery typically produce fuel gas at suitable pressures and qualities for use as fuel in refinery combustion equipment such as heaters, boilers, and turbines. In contrast, VOC emissions from WWTP equipment are generated at low rates, low heating values, and at near atmospheric pressures, such that use of these VOC emissions as fuel in combustion equipment is impractical or infeasible.

In conclusion, since WWTP equipment is not listed as one of the specific facilities in the definition of petroleum refinery in Subpart J, VOC emissions from this equipment is not fuel gas as defined herein. Therefore, the thermal oxidizers A-57 used as abatement devices are not fuel gas combustion devices as defined herein, and therefore not subject to Subpart J.

Finalization of the Subpart J Applicability to A-57.

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

If EPA's comment is correct, then Subpart J would be incorporated into the Title V permit as an applicable requirement for thermal oxidizer A-57, and a schedule of compliance would be established addressing instances of non-compliance. Because incorporation of Subpart J for these units was not part of the Revision 1 proposal, and because the issue deserves consideration based after an opportunity comment by all interested parties, the District will address incorporation of Subpart J for these units in the next revision. In the mean time, no Title V permit shield is provided, and so the Title V permit does not impact the applicability of Subpart J as a federal matter. Accordingly, the District encourages refineries with affected fuel gas combustion devices to be considering their compliance options even while the next revision is pending.

During the discussions of the A-57 Subpart J applicability, some notable points were brought up: 1) the WWTP is a utility system remote from the refinery (lacking any benefits such as access to the refinery vapor recovery system),
2) the WWTP emissions are low quality gas consisting of over 90% non-combustibles (nitrogen and water),
3) the WWTP does not have furnaces or process heaters and the waste gas does not contribute to the refinery heat balance, which is the practical definition of 'fuel gas' customary in the industry,
4) the WWTP emissions are considered 'fuel gas' when abated by A-57, but are not defined as 'fuel gas' when abated by A-37, and

5) the economics of adding additional A-57 abatement to optimize the existing A-37 abatement will be impacted if the monitoring requirements of Subpart J are imposed.

Valero Flare and Thermal Oxidizer Summary Table

Flare or Oxidizer	Year Built	Design Capacity Lb/hr	Is Flare the Primary Abatement Device?	Service or Usage	Possible Sources Abated when Flare in Use	NSPS and NESHAPS Applicability			
						40 CFR 60 Subpart A	*40 CFR 60 Subpart J*	*40 CFR 63 Subpart A*	*40 CFR 63 Subpart CC*
S-16 Acid Gas Flare	1968	79,000	No	Backup abatement device when A24/A64 Tail Gas Unit and/or A56 Flexsorb Unit fails.	S1 and S2, Claus Sulfur Recovery Units	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(4). Sulfur plant vents.
S-17 Butane Tank Flare	1972	16,000	No	Backup abatement device when vapor recovery refrigeration system fails	TK-1726 (exempt Butane Storage Tank)	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 63.640(a)(2) Butane is not a HAP on Table 1
S-18 South Flare	1968	1,200,000	No	Backup abatement device when A13/A26 flare gas recovery system capacity is exceeded and water seal in S18 South Flare knockout drum is broken.	S9 Blowdown System S51 HCU Sandfilter S52 HCU Sandfilter S133 Spent Acid Tank S188 Oil/Water Separator S189 Oil/Water Separator S211 Alkylate Debutanizer S1002 Diesel Hydrofiner S1003 Hydrocracker S1004 Catalytic Reformer S1005 Cat Feed Hydrofiner S1006 Crude Unit S1007 Alkylation Unit S1008 Gasoline Hydrofiner S1009 Jet Fuel Hydrofiner S1010 Hydrogen Plant S1011 HCN Hydrofiner S1012 Dimersol Unit S1014 Cracked Light Ends S1020 Heartcut Tower S1021 Heartcut Saturation S1022 Cat Reformer T-90 S1023 Cat Naphtha T-90 S1024 LCN Hydrotreater S1026 C5/C6 Splitter S1027 C5 Rail Load Rack	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(5): Affected sources routed to fuel gas.
S-19 North Flare	1974	886,000	No	Backup abatement device when A13/A26 flare gas recovery system capacity is exceeded and water seals in both S-18 South Flare and S-19 North Flare knockout drums are broken.		Yes. Note that 60.18 does not apply since S-19 is not subject to any subpart that refers to 60.18 per 60.18(a).	Yes, but exempt from 60.104(a)(1) since only burns process upset gas or fuel gas	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(5): Affected sources routed to fuel gas.
A-57 WWTP Thermal Oxidizer	1998	N/A	Yes	WWTP vapors flow continuously to A-57 and/or carbon adsorption A-37. A-57 heat for hydrocarbon decomposition is from electrical power.	S131 Wastewater Sludge Drum S150 Primary Sludge Thickener S194 Oil/Water Separator S195 Oil/Water Separator S197 Oil/Water Separator S198 Oil/Water Separator S199 Oil Collection Drum S200 Collection Drum	No. Not an Affected Facility per 60.2	No (See discussion in Statement of Basis)	Yes, except 63.11 does not apply since A-57 is not a flare.	Yes
A-14 & A-15 Sulfur Plant Incinerators	1968	N/A	No	Alternate backup abatement device when A24/A64 Tail Gas Unit and/or A56 Flexsorb Unit fails.	S1 and S2, Claus Sulfur Recovery Units	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(4).

Applicability Determination of 40 CFR Part 63 Subpart CC to S-18 and S-19 Flares

40 CFR 63, Subpart CC is NESHAPS for Petroleum Refineries. Per 63.640(a), the affected sources are petroleum refinery process units, which are defined in 63.641. These petroleum refinery process units have fugitive equipment leak emissions as well as defined emission points. Fugitive equipment leak emissions are subject to 40 CFR 63, Subpart CC 63.648 (which has existing sources subject to 40 CFR 60, Subpart VV and new sources subject to 40 CFR 63, Subpart H). These Subpart CC requirements are listed in Table IV-X in the permit. The affected sources emission points are collected and abated by the A-13/A26 vapor recovery system which discharges into the fuel gas system. Since the emission points are routed to the fuel gas system, they are not subject to Subpart CC per 63.640(d)(5). Since the emission points are not subject to Subpart CC, Flares S-18 and S-19, which provide backup abatement to the A13/A26 vapor recovery system (as described above), are not subject to Subpart CC.

Applicability of Regulation 8-2 to Emissions from Flares

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

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

Proper operation is presumed if the flare is operated within its design capacity, if the BTU content of gases flared exceeds 300 BTU/scf, and if a flame is present during flaring. District regulation 12-11 requires flow monitoring, gas composition analysis, and verification of the presence of flame during flaring events.

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

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

Flare Permit Conditions

All of the refinery Title V permits contain permit conditions implementing requirements for flares. As explained in the response to comments on the initial Title V permit issuance, development of Title V permit conditions related to flaring occurred in parallel with the

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

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

The new conditions apply only to flares that are subject to Regulation 12-11. All of the flares that are fully exempt from 12-11 (S-17, the ST-1701 Butane Tank Flare) operate under conditions, and burn materials, that are unlikely to result in visible emissions. Additionally, because they are not emergency flares, they are not likely to encounter flow rates above capacity. The reasons that led to exemption of these flares from 12-11 are also the reasons why additional Title V conditions addressing these three areas are not appropriate. .

<u>Proper operation</u>

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

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

Design Capacity

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

Part 2 requires recordkeeping to demonstrate compliance with Part 1.

Fuel value

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

Flame

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

Visible emissions

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

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

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

Part 5 states that, if the surveillance is by a trained observer, compliance will be demonstrated using EPA Method 9 (the method specified in Regulation 6-301). Otherwise, an untrained observer observes the stack, and if visible emissions are detected for three consecutive minutes, the flare violates the surrogate standard contained in the permit condition.

<u>NSPS Subpart J</u>

Any flare built or modified after June 11, 1973 is subject to NSPS Subpart J. Modification of a flare, as defined in Subpart J, would likely only occur if the burner tip is replaced by one with a larger capacity – which is likely to be a rare event. As a result, NSPS Subpart J typically applies to flares that are built after the effective date. Valero S-19, the ST-2103 North Flare is covered by NSPS Subpart J.

There is only one requirement for flares subject to subpart J: a limitation on the sulfur content of gas combusted, and the monitoring to demonstrate compliance. Subpart J exempts from this requirement the flaring of upset gases, and fuel gas that is the result of an emergency breakdown.

Some of the facilities have identified NSPS flares (flares built after 1973) that are not designed to burn anything other than upset gases or fuel gases that result from emergency breakdowns. These flares are therefore exempt from the NSPS monitoring requirement, provided they are used only in that manner. However, at least some of these flares have a potential for broader use because the physical construction that enables flaring of gases from upsets or emergencies also enables flaring of gases from routine processes.

This is typical of situations at oil refineries where the refinery has stated that a flare is used only for upsets and emergencies, and where there is not information to the contrary. The District then proceeds on the assumption that the flare is exempt from the H2S limit of Subpart J. The District's continuing efforts to monitor the applicability of Subpart J to flares should be significantly aided in the future by information generated pursuant to BAAQMD Regulation 12, Rule 11.

Part 7 imposes a condition on these flares to assure compliance with the exemption criteria. The same prohibition found in Part 7 could be enforced by directly enforcing applicability of Subpart J, that is, by a determination that the facility has been in violation of Subpart J if, for instance, routine disposal of gases through flaring has occurred. However, enforcement of Subpart J in federal court (through the CAA citizen enforcement provisions) is an unwieldy tool for use by a permitting agency such as the District that can much more readily enforce in state court. By incorporating the prohibition against routine flaring into Title V permits, enforcement of this prohibition becomes substantially more feasible for the District.

S-18 and NSPS Subpart J:

40 CFR 60.100(a) specifies affected facilities subject to Subpart J, including fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices (such as flares), and Claus sulfur recovery units greater than 20 long tons per day. Furthermore, 40 CFR 60.100(b) includes effective dates for which Subpart J applies, if an affected facility commences construction or modification after the effective date. For fuel gas combustion devices (such as flares), the effective date is June 11, 1973. Since S-18 was constructed prior to June 11, 1973 and has not been modified since that date, S-18 is not an affected facility subject to Subpart J. A flare can only become an affected facility subject to Subpart J if it has been constructed or modified after June 11, 1973. The presence of NSR sources in the refinery does not automatically make a flare an affected facility subject to Subpart J.

Issues raised by comments

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

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

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

Comment: A flaring event that lasts between 3 and 15 minutes could exceed opacity limits, and this type of violation would go unmonitored under existing permit monitoring requirements. The District implies that opacity limitations need only be monitored if the emission is “significant” or is “ a real problem.” The District’s opacity regulation does not allow for these exemptions from its requirements.

Response: The comment is based upon the faulty premise that the purpose of Title V monitoring is to detect every violation. Continuous monitoring for violations can be cost-prohibitive, impractical, and even, in a case such as this, at odds with good air pollution practices. The purpose of Title V monitoring is to provide reasonable assurance of compliance. This requires a balance between cost and difficulty of the testing, and the likelihood and severity of non-compliance. See, for example, EPA's guidance on the required monitoring for other sources subject to visible emission standards.

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

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

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

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

Comment: Please also include record-keeping and reporting requirements for those flares subject to NSPS J but exempt from the fuel H2S limit.
Response: It is unclear what monitoring is being requested. If the proposal is to include monitoring to ensure that non-exempt gases are not vented to exempt flares, the requirements of

Regulation 12-11-401 should suffice. We do not consider, however, this monitoring to be federally enforceable. The only federally enforceable monitoring for assuring compliance with Subpart J is spelled out in Subpart J.

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

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

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

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

EPA Comment: The permits must also require monitoring the flow rate if necessary to determine compliance with residence time requirements. This monitoring is in addition to the temperature monitoring that the District already includes.
Response: Valero has oxidizers subject to 40 CFR 61, Subpart FF. Subpart FF gives you three choices for compliance for incinerators: 95% control of VOC, 20 ppmv benzene, or 1400 degrees F and 0.5 sec residence time. The standard requires monitoring of a parameter or parameters, but doesn't specific the parameter. In the past, Valero had told me that they complied at the main refinery with the requirement to show 95% control with a performance test instead of design calculations. This is an option.

Sewer Systems and Process Drains

<u>Applicability Determination of 40 CFR Part 61 Subpart FF and 40 CFR Part 63 Subpart CC to Valero's Sewer Pipeline and Process Drains</u>

The Valero Benicia Refinery is subject to Subpart CC. The Subpart CC wastewater provisions, 63.647, reference Subpart FF. Valero complies with FF through 61.342(e)(2)(i),

which allows the facility 6 Mg/yr of uncontrolled benzene waste. Thus, facilities are allowed to choose whether the benzene waste streams are controlled or uncontrolled, as long as the uncontrolled stream quantities total less than 6 Mg/yr.

Valero includes benzene waste in its sewer (S-161) and process drains (S-32105) as part of the uncontrolled benzene waste allowance of 6 Mg/yr. Because the sewer and process drains are uncontrolled, they are not subject to 61.346, the standards for individual drain systems. Thus, CC and FF are not listed as applicable requirements for the process sewer and drains. However, the applicable recordkeeping and reporting requirements for 61.342(e)(2)(i) are listed in Table IV-Refinery.

<u>Applicability Determination of 40 CFR Part 60 Subpart QQQ to Valero's Sewer Pipeline and Process Drains</u>

Background:

The Valero Benicia Refinery was constructed in 1968, including a sewer collection system (S-161) consisting of process drains, catch basins, sewer lines, junction boxes, etc. The existing sewer system manages both stormwater and oily wastewater from process units and tankage.

Regulatory Analysis:

60.690(a)(1) specifies that the provisions of Subpart QQQ apply to affected facilities which were constructed, modified, or reconstructed after May 4, 1987.

Affected facilities include: individual drain systems, oil-water separators, and aggregate facilities.

The following definitions are included in this subpart:

Wastewater system means any component, piece of equipment, or installation that receives, treats, or processes oily wastewater from petroleum refinery process units.

Oily wastewater means wastewater generated during the refinery process which contains oil, emulsified oil, or other hydrocarbons. Oily wastewater originates from a variety of refinery processes, including cooling water, condensed stripped steam, tank draw-off, and contact process water.

Stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting stormwater and which is segregated from the process wastewater collection system.

60.692-1(d)(1) specifies that stormwater sewer systems are not subject to Subpart QQQ.

Conclusion:

The original sewer system has not been modified since May 4, 1987 when Subpart QQQ became effective.

Two process units have been constructed in the Refinery since 1987. However, the sewer systems in both process units are designed and operated for the sole purpose of managing only stormwater. Process wastewater from these units is hard-piped to an enclosed system, and never enters the refinery sewer system. Finally, the sewer lines leaving these two units are segregated from the main sewer system by underflow weirs located in the junction boxes, which prevent emissions from backflowing into these units.

Since the original sewer system has not been modified since 1987, and the stormwater sewer systems in the two process units constructed after 1987 are exempt from Subpart QQQ in accordance with 60.692-1(d)(1), the entire refinery sewer system (S-161) is exempt from NSPS Subpart QQQ.

District Permit Applications Not Included In This Proposed Permit

This facility sends a large number of permit applications to the District every year. Review of the following permit applications was not completed in time to include the results in this version of the Title V permits. The Title V permit will be revised periodically to incorporate these applications as permit revisions following the procedures in Regulation 2, Rule 6, Major Facility Review.

Application #	Project Description
5846	Valero Improvement Project
7980	Transfer of selected Storage Tank assets to Valero Logistics Operations Facility B5574

In addition, and related to the last item in the table above, Valero Logistic Operations has submitted Application 8915 for a Title V permit for the Storage Tank Assets which it now owns. The sources being transferred are S-57 through S-62, S-67, S-68, S-70 through S-72 and S-74.

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.

The BAAQMD Compliance and Enforcement Division has conducted a review of compliance over the past year and has no records of compliance problems at this facility during the past year.

VI. Permit Conditions

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

Conditions that were changed in this revision of the permit are as follows:

Condition 125 and 126 – Part 2 was reinstated and updated to require operation and maintenance for the H2S monitor. (EPA Comment # 196)

Condition 9296 – Deleted Part A1 and added Part A4 per MTBE Phaseout Application 2035. **Corrected by deleting Parts D8, D9 and D10, which were not included in the NSR Authority to Construct.**

Condition 10797 – Revised per MTBE Phaseout Application 2035.

Condition 10574 – Clarified Part H to make it clear that depressurization gas is to be vented to a control device.

Condition **11879,** 11882**, 11188 and 13319** – ~~Deleted Part 7 because temperature excursions are not allowed under 40 CFR 61 Subpart FF. (EPA Comment # 185)~~

~~Condition 13319 – Deleted Part 7 because temperature excursions are not allowed under 40 CFR 61 Subpart FF. (EPA Comment # 213)~~**Revised to require a minimum A-57 Thermal Oxidizer temperature limit averaged over a 3 hour period.**

Condition 18043 – Deleted Parts 1 and 3 since these fugitive requirements are duplicated in BAAQMD Regulation 8, Rule 18.

Condition 19177 – ~~Added Part 18c monitoring for ammonia injection. (Valero Comment # C40~~**Corrected condition to include the correct version, which did not have monitoring for ammonia injection.**~~)~~

Condition 19466 – Updated Part 3 to be consistent with the specific source equipment subject to BAAQMD Regulation 6-301 compliance monitoring. (Valero Comment # 9)
Condition 19466 – Updated Part 4 to provide unscheduled start-up/shutdown notification when the event occurs on a weekend/holiday period.
Condition 19466 – Updated Part 7 to be consistent with the specific source equipment subject to BAAQMD Regulation 6-310 compliance monitoring. (Valero Variance Item #1)
Condition 20806 – This Flare condition was replaced as discussed in Section C.IV above. **The effective date was revised to 12/1/04 per May 27, 2004 Administrative Amendment.**
Condition 21233 – This "NOx Box" condition was added as discussed in Section C.IV above. **The effective date was revised to 12/1/04 per May 27, 2004 Administrative Amendment.**

The regulatory basis is listed following each condition. The regulatory basis may be a rule or regulation. The District is also using the following terms for regulatory basis:

- BACT: This term is used for a condition imposed by the Air Pollution Control Officer (APCO) to ensure compliance with the Best Available Control Technology in Regulation 2-2-301.
- Cumulative Increase: This term is used for a condition imposed by the APCO which limits a source's operation to the operation described in the permit application pursuant to BAAQMD Regulation 2-1-403.
- Offsets: This term is used for a condition imposed by the APCO to ensure compliance with the use of offsets for the permitting of a source or with the banking of emissions from a source pursuant to Regulation 2, Rules 2 and 4.
- PSD: This term is used for a condition imposed by the APCO to ensure compliance with a Prevention of Significant Deterioration permit issued pursuant to Regulation 2, Rule 2.
- TRMP: This term is used for a condition imposed by the APCO to ensure compliance with limits that arise from the District's Toxic Risk Management Policy.

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.

The tables below contain only the new limits in the reopened permit for which there is no monitoring or inadequate monitoring in the applicable requirements. The District has examined the monitoring for other limits and has determined that monitoring is adequate to provide a reasonable assurance of compliance. Calculations for potential to emit will be provided in the discussion when no monitoring is proposed due to the size of a source.

NOx Discussion:

There are no changes in the permit sources where NOx monitoring is missing or inadequate.

CO Discussion:

There are no changes in the permit sources where CO monitoring is missing or inadequate.

SO2 Discussion:

There are no changes in the permit sources where SO2 monitoring is missing or inadequate.

PM Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
S-167, S-168, Seal Oil Spargers	BAAQMD Regulation 6-301	Ringelmann 1 for more than 3 minutes in any hour	No monitoring
S-167, S-168, Seal Oil Spargers	BAAQMD Regulation 6-310	0.15 grains per dscf	No monitoring

PM Discussion:

This change in the Seal Oil Spargers is actually a correction. The December 1, 2003 permit listed S-167 and S-168 with no monitoring because the source is capable of exceeding visible emissions or grain loading standard only during process upset. Under such circumstances, other indicators will alert the operator that something is wrong. In fact, these sources vent to the closed refinery fuel gas system. In addition, the December 1, 2003 permit showed Seal Oil Sparger S-160 with no 6-310 monitoring. This was an error. BAAQMD Condition # 19466, Part 7 requires S-160 monitoring for 6-310 compliance verification.

POC Discussion:

There are no changes in the permit sources where POC monitoring is missing or inadequate.

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.

IX. Permit Shield

The District rules allow two types of permit shields. The permit shield types are defined as follows: (1) A provision in a major facility review permit explaining that specific federally enforceable regulations and standards do not apply to a source or group of sources, or (2) A provision in a major facility review permit explaining that specific federally enforceable applicable requirements for monitoring, recordkeeping and/or reporting are subsumed because other applicable requirements for monitoring, recordkeeping, and reporting in the permit will assure compliance with all emission limits.

The second type of permit shield is allowed by EPA's White Paper 2 for Improved Implementation of the Part 70 Operating Permits Program. The District uses the second type of permit shield for all streamlining of monitoring, recordkeeping, and reporting requirements in Title V permits. The District's program does not allow other types of streamlining in Title V permits.

This facility has the first and second types of permit shield. However, since the December 1, 2003 permit, there has been ~~no~~ **one** additional permit shield **(Table IX A-6)**~~s~~. There was **also** one correction to the permit shields. BAAQMD 10-52 and 10-59 were deleted from Table IX B-24 because they are non-applicable requirements, not subsumed requirements. Then, Table IX A-5 was added to show these Subpart VV and Subpart GGG non-applicability requirements for equipment leaks. (EPA Comment # 17)

Table IX A-5
Permit Shield for Non-Applicable
Fugitive Sources
`S-51 HCU Feed Filter R-410A
S-52 HCU Feed Filter R-410B
S-1002 Diesel Hydrofiner
S-1003 Hydrocracker (HCU)
S-1005 Catalytic Feed Hydro.
S-1006 Pipestill Unit
S-1007 Alkylation Unit
S-1008 Gasoline Hydrofiner
S-1009 Jet Fuel Hydrofiner
S-1011 Heavy Cat Naphtha Hydrofiner
S-1014 Cat Light Ends
S-1020 Heartcut Tower (MRU), except for Heartcut Stream
S-1021 Heartcut Sat Unit (MRU) except for Heartcut Stream
S-1022 Cat Ref T90 Tower MRU
S-1023 Cat Nap T90 Tower MRU
S-1024 Lt Cat Nap Hydrotreater MRU
S-1026 C5/C6 Splitter (MRU)
Heartcut Stream (MRU) (2)
Fluid Catalytic Cracking Unit
Virgin Light Ends, excluding S-1002, S-1008, and S-1009

Citation	Title or Description	Reason Not Applicable
40 CFR 60 Subpart VV	Standards of Performance For Equipment Leaks of VOC In The Synthetic Organic Chemicals Manufacturing Industry.	Per 63.640 (p), equipment leaks that are also subject to Part 60 (NSPS) and Part 61 (NESHAPS) are only required to comply with Part 63 (MACT).
40 CFR 60 Subpart GGG	Standards of Performance For Equipment Leaks Of VOC In Petroleum Refineries	Per 63.640 (p), equipment leaks that are also subject to Part 60 (NSPS) and Part 61 (NESHAPS) are only required to comply with Part 63 (MACT).

Table IX A-6
Permit Shield for Non-Applicable
S-16 Acid Gas Flare
S-17 Butane Flare
S-18 South Flare
S-19 North Flare

Citation	Title or Description	Reason Not Applicable
Regulation 8, Rule 2	**Miscellaneous Operations**	**Incineration sources with destruction efficiency > 90% exempt from all Regulation 8 Rules per 8-1-110.3.**

D. Alternate Operating Scenarios:

No alternate operating scenario has been requested for this facility.

E. Compliance Status:

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

F. Permit Updates and Changes since the Final December 1, 2003 Permit

Changes made to the Final December 1, 2003 Permit to produce the Draft Reopened Permit published for Public Comment

Section I, II, III changes

1. In Table IIA, added reference to MTBE Phaseout Application 2035 in the Throughput column for S-40, S207, S209 and S-210. Added S-211 Alkylate Debutanizer which is the only equipment in the MTBE Unit that still is operated. (VRC#A5)

2. In Table IIC, added A-64 Spare Tail Gas Hydrogenation Unit consistent with Application 8028.

3. In Table IIC, deleted the reference to continuous monitoring on A-24 and A-56. The H2S and TRS monitor does not monitor the SO2 limit of 9-1-307. Furthermore, it is an operations troubleshooting device and deleting the term 'continuous' will avoid any inference that it is a CEM for SO2. Note also that S-1 and S-2 are not operated without abatement A-24, A-64 and A-56. All SO2 in the S-1 and S-2 Tail Gas has to be converted to H2S in A-24 or A-64 to prevent poisoning the absorbent in A-56. Therefore SO2 emissions are low and well below both the 250 ppm and the 100 lb/day threshold of 9-1-307.

Section IV, Applicable Requirements

1. In Table IV-X, added reference to Condition 18043, Part 1 to S-1007, 1012 and 1014 per MBTE Phaseout Application 2035. (VRC#B115)

2. In Table IV-J9, Condition 10797 Parts 1, 4, 6 & 7 were revised and Parts 2, 5, 8 & 9 were deleted per MTBE Phaseout Application 2035. (VRC#B125, 126, 127, 128, 129)

3. In Table IV-A22.1 and A22.2, added ammonia monitoring to Condition 19177, Part 18(c), consistent with the condition text in Section VI. (VRC#C40)

4. In Table IV-J39 Condition 11882, Part 7 was deleted because temperature excursions are not allowed under 40CFR 61 Subpart FF. (EPA#185)

5. In Tables IV-A1 & A2, Condition 125 and 126, Part 2 was reinstated and updated to require operation and maintenance of the H2S monitor. (EPA#196)

6. In Tables IV-H4.2 & H5.2, Condition 13319, Part 7 was deleted because temperature excursions are not allowed under 40CFR 61 Subpart FF. (EPA#213)

7. In Table IV-B1 for S-8, S-10 and S-12, Condition 19466, Part 7 was revised to agree with the text in Section VI. (VRC#V1)

8. In Table IV-B2 for S-11, Condition 19466, Part 7 was revised to agree with the text in Section VI. (VRC#V1)

9. In Table IV-C4.1 for S-160, Condition 19466, Part 7 was revised to agree with the text in Section VI. (VRC#V1)

10. In Table IV-B4 for S-176, Condition 19466, Part 7 was revised to agree with the text in Section VI. (VRC#V1)

11. In Table IV-B6 for S-232, Condition 19466, Part 7 was deleted to agree with the corrected text in Section VI. (VRC#V1)

12. In Table IV-B7 for S-233, Condition 19466, Part 7 was revised to agree with the text in Section VI. (VRC#V1)

13. In Table IV-A20 for S-237, Condition 19466, Part 7 was deleted to agree with the corrected text in Section VI. (VRC#V1)

14. In Table IV-H4.1, deleted 40 CFR 61.349(f) and (f)(1) which do not apply since S-188 is vented to the refinery fuel gas system. (VRC#V3)

15. In Table IV-H5.1, added 40 CFR 61.340(a), (c) and (d) for S-189. Deleted all the other Subpart FF citations since they do not apply for this unit that is vented to the refinery fuel gas system. (VRC#V3)

16. In Table IV-H4.2, added the Subpart FF citations that were deleted in error. (VRC#V3)

17. In Tables IV-J11 and J12, switched the S-87 and S-89 tank errors in the tables. S-89 has a solid guide pole and must be on Table IV-J11. S-87 has a slotted guide pole and must be on Table IV-J12. (VRC#V4)

18. In Table IV – Refinery Generally Applicable Requirements which Require Routine Monitoring, deleted Regulation 9-1-302 because since the Ground Level Monitoring for SO2 was installed prior to 1/1/1980, Regulation 9-1-110 exempts the facility from 9-1-

302.

19. In several Section IV tables the effective dates were corrected from 4/01/03 to 4/01/04 to be consistent with Condition 19466, Part 16.

20. In Tables IV-A1 and A2, corrected the Condition 125 and 126 Part 4 that reference the A-24, A-56 and A-64, consistent with Condition 125 and 126 in Section VI.

21. Added Table IV-D1 for S-1004 Catalytic Reformer. (VRC#B79)

22. Added Table IV-D2 for S-1006 Crude Unit. (VRC#B79)

23. Added Table IV-D3 for S-1007 Alkylation Unit. (VRC#B79)

24. Added Table IV-D4 for S-1010 Hydrogen Unit. (VRC#B79)

25. Added Table IV-D5 for S-1012 Dimersol Unit. (VRC#B79)

26. Added Table IV-D6 for S-1014 Virgin Light Ends Splitter. (VRC#B79)

27. Added Table IV-D7 for S-1024 Light Cat Naphtha Hydrofiner. (VRC#B79)

28. Revised Flare Condition 20806, Table IV-A8.1, IV-8.2 and IV-9, and Tables VII-A8.1, A8.2 and A9 to reflect the latest flare operation and monitoring requirements. Only S-19 is subject to Subpart J because it was constructed after 6/11/1973. S-19 only burns upset or fuel gas as defined in 40 CFR 60.101 so it is exempt from the sulfur oxide standard of Subpart J. The revision to Condition 20806 adds clarity to the previous version. (VRC#3, V2, B27, C64 and D14) Also added Regulations 12-11-502.1, 12-11-502.2, 12-11-601.1 and 12-11-602 to Tables IV-A8.1 and A9 for clarification. (Valero Appeal #3)

29. Revised Condition 9296 to delete Part A1 and add Part A4 as approved in Application 2035 MTBE Phaseout Project. Added Tables IV-D8 and VII-D8 for the S-211 Alkylate Debutanizer which is the only item in the former MTBE Unit that is still in operation.

30. Added Condition 21233 for Regulation 9-10 Refinery-wide Compliance (“NOx Box”). Revised Tables IV-A6.1, A6.2, A10, A11, A12, A15, A16, A18 and A19, and Tables VII-A6.1, A6.2, A10, A11, A12, A15, A16, A18 and A19. (VRC#7, B20, C49, & D9)

31. Revised Condition 19566, Part 4 to allow unscheduled start-up or shutdown notification on the next business day when the event occurs on a weekend or holiday period. Also updated Table IV – Refinery Generally Applicable Condition.

Section VI, Permit Conditions

1. Condition 10797 Parts 1, 4, 6 & 7 were revised and Parts 2, 5, 8 & 9 were deleted per MTBE Phaseout Application 2035. (VRC#C15, 16, 17, 18, 19)

2. Condition 19177, Part 18c was revised to add monitoring for ammonia injection. (VRC#C40)

3. Condition 11882, Part 7 was deleted because temperature excursions are not allowed under 40CFR 61 Subpart FF. (EPA#185)

4. Condition 125 and 126, Part 2 was reinstated and updated to require operation and maintenance of the H2S monitor. (EPA#196)

5. Condition 13319, Part 7 was deleted because temperature excursions are not allowed under 40CFR 61 Subpart FF. (EPA#213)

6. Condition 19466, Part 7 was modified for S-10 and S-12 to require the annual source test only when the sources are returned to service. (VRC#V1)

7. Condition 19466, Part 7 was modified to allow the S-11 annual source test scheduling flexibility. (VRC#V1)

8. Condition 19466, Part 7 was modified to require a S-160 and S-233 source test plan and procedure be prepared and submitted by 4/1/04 for District approval. This is because there is concern that the cited ST-15 is not applicable for these small (<3”) sources. The annual source test would commence no more than 90 days after the District approval of the submission. (VRC#V1)

9. Condition 19466, Part 7 was modified to delete S-232 because it is a closed unit that discharges into S-233. (VRC#V1)

10. Condition 19466, Part 7 was modified to delete S-237 to be consistent with the other fuel gas fired boilers. Since all the other sources in 19466-7 are material handling, it is likely that S-237 was included by mistake. (VRC#V1)

11. Revised Condition 9296 to delete Part A1 and add Part A4 as approved in Application 2035 MTBE Phaseout Project.

12. Added Condition 18043 as approved in Application 2035 MTBE Phaseout Project.

13. Condition 19466, Part 3 was modified to delete S-232. S-232 is a closed unit that discharges into S-233. In addition, provisions were added for S-10, S-12 and S-176 to require monitoring only if the equipment is returned to service. (VRC#9)

14. Revised Flare Condition 20806, Table IV-A8.1, IV-8.2 and IV-9, and Tables VII-A8.1, A8.2 and A9 to reflect the latest flare operation and monitoring requirements. Only S-19 is subject to Subpart J because it was constructed after 6/11/1973. S-19 only burns upset or fuel gas as defined in 40 CFR 60.101 so it is exempt from the sulfur oxide standard of Subpart J. The revision to Condition 20806 adds clarity to the previous version. (VRC#3, V2, B27, C64 and D14)

15. Added Condition 21233 for Regulation 9-10 Refinery-wide Compliance ("NOx Box"). Revised Tables IV-A6.1, A6.2, A10, A11, A12, A15, A16, A18 and A19, and Tables VII-A6.1, A6.2, A10, A11, A12, A15, A16, A18 and A19. (VRC#7, B20, C49, & D9)

16. Revised Condition 194~~5~~66, Part 4 to allow unscheduled start-up or shutdown notification on the next business day when the event occurs on a weekend or holiday period. Also updated Table IV – Refinery Generally Applicable Condition.

Section VII, Monitoring Requirements

1. In Table VII-A22.1 and A22.2, added continuous ammonia injection monitoring, consistent with Condition 19177, Part 18(c) in Section IV and VI. (VRC#C40, D43)

2. In Table VII-A20, FP grain loading monitoring Condition 19466, Part 7 was deleted to be consistent with the other fuel gas fired boilers. Since all the other sources in 19466-7 are material handling, it is likely that S-237 was included in 19466-7 by mistake. (VRC#V1)

3. In Table VII-B1, modified FP grain loading 6-310 monitoring to indicate the annual source test only applied to S-10 and S-12 when returned to service. (VRC#V1)

4. In Table VII-C4, modified FP grain loading 6-310 monitoring to indicate the annual source test commences for S-160 Seal Oil Sparger after the source test plan and procedure is approved by the District. (VRC#V1)

5. In Table VII-B4, modified FP grain loading 6-310 monitoring to indicate the annual source test only applies to S-176 when dry salt is added to the tank. (VRC#V1)

6. In Table VII-B7, modified FP grain loading 6-310 monitoring to indicate the annual source test commences for S-233 Storage Bin after the source test plan and procedure is approved by the District. (VRC#V1)

7. In Table VII-B6, FP grain loading monitoring Condition 19466, Part 7 was deleted. Since S-232 is a closed unit discharging into S-233, it is likely that S-232 was included in 19466-7 by mistake. (VRC#V1)

8. In Tables VII-J19, J20, J30 and J31.1, the monitoring for 8-5-301 was deleted. These tanks are covered by the low vapor pressure exemption 8-5-117 so 8-5-301 would not apply. Also, the monitoring requirement citation for 8-5-117 was corrected from 8-5-501 to the more specific 8-5-501.1 to be consistent with citations elsewhere in Section VII. (VRC#V5)

9. Added Table VII-D1 for S-1004 Catalytic Reformer. (VRC#D62)

10. Added Table VII-D2 for S-1006 Crude Unit. (VRC#D62)

11. Added Table VII-D3 for S-1007 Alkylation Unit. (VRC#D62)

12. Added Table VII-D4 for S-1010 Hydrogen Unit. (VRC#D62)

13. Added Table VII-D5 for S-1012 Dimersol Unit. (VRC#D62)

14. Added Table VII-D6 for S-1014 Virgin Light Ends Splitter. (VRC#D62)

15. Added Table VII-D7 for S-1024 Light Cat Naphtha Hydrofiner. (VRC#D62)

16. Revised Condition 9296 to delete Part A1 and add Part A4 as approved in Application 2035 MTBE Phaseout Project. Added Tables IV-D8 and VII-D8 for S-211 Alkylate Debutanizer which is the only item in the former MTBE Unit that is still in operation.

17. In Tables VII-J14, J38 and J41, the monitoring for 8-5-117 was deleted. These tanks are subject to Regulation 8-5 and will likely never store low vapor pressure material. (VRC#V5 follow-up)

18. Revised Flare Condition 20806, Table IV-A8.1, IV-8.2 and IV-9, and Tables VII-A8.1, A8.2 and A9 to reflect the latest flare operation and monitoring requirements. Only S-19 is subject to Subpart J because it was constructed after 6/11/1973. S-19 only burns upset or fuel gas as defined in 40 CFR 60.101 so it is exempt from the sulfur oxide standard of Subpart J. The revision to Condition 20806 adds clarity to the previous version. (VRC#3, V2, B27, C64 and D14)

19. Added Condition 21233 for Regulation 9-10 Refinery-wide Compliance ("NOx Box"). Revised Tables IV-A6.1, A6.2, A10, A11, A12, A15, A16, A18 and A19, and Tables VII-A6.1, A6.2, A10, A11, A12, A15, A16, A18 and A19. (VRC#7, B20, C49, & D9)

Section IX, Permit Shield

1. Deleted BAAQMD 10-52 and 10-59 from Table IX B-24 because they are non-applicable requirements, not subsumed requirements. Added Table IX A-5 detailing these Subpart VV and Subpart GGG non-applicable requirements for equipment leaks. (EPA#17)

Section X, Glossary

1. Added definitions for Start-up, Shutdown, and Process Unit for reporting purposes.

Changes made to the Draft Reopened Permit in Response to the comments received from the Public Comment Period:

Section I, II, III changes

1. In Table IIA, the text in the throughput column of S-151 was revised for clarification. (VR1#A1)

2. **In Table IIA, the text in the capacity and throughput columns of S-211 was revised for clarification. (VR1#A2)**

3. **In Table IIA, the furnace tag number F-4460 was added to the text in the description of S-220. (VR1#A3)**

4. **Table III was updated to reflect the recent incorporation of BAAQMD Regulation 8, Rule 3 and 4 into the SIP. (VR1#A5&A6)**

5. **Table III was updated to reflect newly added monitoring provisions of BAAQMD Regulation 8, Rule 10. The citation was removed from Table III and added in expanded form to Table IV – Refinery Generally Applicable Requirements which Require Routine Monitoring. (VR1#A7 & B1)**

6. **Table III was updated to delete redundant BAAQMD Regulation 11, Rule 12. 11-12 incorporates Benzene Waste NESHAPS 40 CFR 61 Subpart FF, which is shown with detailed citations in Table IV – Refinery Generally Applicable Requirements which Require Routine Monitoring. (VR1#A9)**

7. **In Table IIA, the text in the throughput column of S-77 was revised to clarify the gasoline service change of S-77 due the MTBE Phaseout Project. (VR1#A13)**

8. **In Table IIA, the text in the description and throughput columns of S-207 was revised to delete the reference to MTBE due the MTBE Phaseout Project. (VR1#A14)**

9. **In Table IIA, the text in the description column of S-209 was revised to reflect current service due the MTBE Phaseout Project. (VR1#A15)**

10. **In Table IIB, two exempt sources were added. These sources were in the December 1, 2003 Statement of Basis but were inadvertently omitted from Table IIB. (VR1#17)**

11. **In Table III, several citation dates were updated for SIP adopted regulations to reflect the Federal Register dates. In addition, some BAAQMD regulation and Title 40 citation dates were updated to reflect the current versions. (VR1#18).**

12. **In Table IIA, the text in the description column of S-210 was revised for clarification due the MTBE Phaseout Project. (VR1#A16)**

13. **In Table IIC, 40 CFR 60, Subpart Db, 60.44b(e) was deleted. 60.44b(l)(1) is the applicable citation because the Cogen unit was constructed after July 9, 1997. (VR1#A4)**

14. **Added the four refinery flares S-16, S-17, S-18 and S-19 to Table II-C since these devices provide backup abatement service. (EP1#9)**

15. Revised the sources abated by A-13 and A-26 to include all abated sources.

Section IV, Applicable Requirements

1. **Table III was updated to reflect newly added monitoring provisions of BAAQMD Regulation 8, Rule 10. The citation was removed from Table III and added in expanded form to Table IV – Refinery Generally Applicable Requirements which Require Routine Monitoring. (VR1#A7 & B1)**

2. **In Table IV Refinery Generally Applicable Condition 40 CFR 63 Subpart UUU was expanded to show detailed citations. (VR1#B2)**

3. **In Tables IV-A1 & -A2, SIP Regulation 9-1-307 was deleted because BAAQMD Regulation 9-1-307 was adopted in the SIP. (VR1#B3)**

4. **Deleted Condition 19466, Part 3 in Table IV-B6 and removed S-232 from Condition 19466, Part 3 in Tabless IV-A1, A2, A20, B1, B2, B4, B7 and C4.1 to be consistent with the text in Section VI (VR1#B5, B26)**

5. **Added BAAQMD 1-523 and SIP 1-523 for Parametric Monitoring to Tables IV-A3, A6.1, A6.2, A10, A11, A12, A-15, A-16, A-18, A-19, F1, J36, J37, J38, J39 and J40. (VR1#B6)**

6. **Added BAAQMD 1-107 Combination of Emissions to Tables IV-A13.1, A14.1, and A14.2. (VR1#B11)**

7. **Added 40 CFR 60 Appendix F, Procedure 1 to Table IV-A18. (VR1#B12)**

8. **In Tables IV-A19, A20 and A22.2, added 40 CFR 60 Appendix B, Performance Specification 2, NOx Continuous Emission Monitoring Systems. (VR1#14)**

9. **Corrected the tag number of S-1026 C5/C6 splitter (was shown as S-1025) in Condition 10574 in Section VI and in Part 12 shown in Tables IV-A19, D3, D6, H1.1 and J18. (VR1#B15, C1)**

10. **In Table IV-A21, changes the Federal Enforceability Status of Condition 18748, Parts 2 and 3 from Y to N since BAAQMD regulations 9-8-330 and 9-8-530 are not adopted into the SIP. (VR1#B17)**

11. **Added BAAQMD Regulation 9-8-530 to Tables IV-A21 and A23. (VR1#B18)**

12. **Added NSPS 40 Part 60 Appendix B Performance Specification 7, H2S Continuous Emission Monitoring Systems and NSPS Title 40 Part 60 Appendix F Procedure 1, QA Requirements for Gas Continuous Emission Monitoring Systems to Table IV-A22.1. (VR1#B19)**

13. In Table IV-B5, Condition 9296, Part B9 was updated to be consistent with Section VI. (VR1#B25)

14. In Table IV-G1, added two new applicable requirements based on the 10/16/2002 version of Regulation 8, Rule 16. Also deleted 8-16-501.6 since S-177 is not subject to the limited exemption of 8-16-121. (VR1#B30, B32 and B33)

15. In Tables IV-H1.1 and H1.2, added 8-8-601 Wastewater Analysis for Critical OCs. (VR1#B35)

16. Conditions 11879, 11882, 11188 and 13319, Parts 4 and 7 were modified to require a minimum thermal oxidizer temperature limit averaged over a consecutive 3-hour period with no allowable temperature excursions. Tables IV and VII-H4.2, H5.2, J36, J37 and J39 were updated to reflect these changes. (EPA#185, 213 and VR1#B37, C2, D28)

17. In Table IV-I, BAAQMD Regulation 8, Rule 18 was updated based on the rule amendments of 01/21/2002, Subpart VV reporting citations were updated, and several omissions were corrected. (VR1#B38, B39, B40, B41 and B42)

18. In Table IV-X, added Condition 10574, Part 52 and NESHAPS Part 63, Subpart CC applicability to the S-211 requirements. Deleted Conditions 815, 15512 and 17835 for S-1006, S-1010 and S-1027, respectively, since these conditions are not fugitive components related and are included in Tables IV-D2, D4, and B8. Revised Note 4 to clarify contents of BAAQMD Permit Conditions column. (VR1#B43 B44, B45 and B46)

19. Condition 18043, Parts 2 and 3 were deleted since these fugitive requirements are duplicated in BAAQMD Regulation 8, Rule 18. Tables IV-D3, D5, D6 and D8 were updated to be consistent. (VR1#B28, C3)

20. In Table IV-J2, added 8-5-604 that was inadvertently omitted. (VR1#B48)

21. Updated NSPS 40 CFR 60 Subpart Kb to reflect the 10/15/2003 version per 68 FR 59328. Tables IV-J9, J13, J18, J30, J38, J40 and J41 impacted. (VR1#B49, B67, B68)

22. In Table IV-J10, deleted 8-5-321.4 because it is a requirement for resilient-toroid-seal equipped tanks (the citation has the wrong title) which S-112 does not have. (VR1#B50)

23. In Table IV-J12, added 8-5-320.5.3 that was inadvertently omitted. (VR1#B51)

24. In Tables IV-J13 and J34, deleted 40 CFR 60.112b(a)(1)(ii)(A) & (C) because only 60.112b(a)(1)(ii)(B) is the only correct option for IFRs with double seals. (VR1#B52)

25. In Table IV-J29, added 8-5-501.1 that was inadvertently omitted. (VR1#B53)

26. In Tables IV-J35, deleted 40 CFR 60.112b(a)(1)(ii)(A) because only 60.112b(a)(1)(ii)(C) is the only correct option for IFRs with a single mechanical shoe seal. (VR1#B54)

27. Condition 9296, Parts D8, D9 and D10 were deleted. It is unclear where these Parts originated, but these 3 conditions were in Databank and this was the basis for the first response for this comment (VRC#B38). Recent review of Application 2035, MTBE Phaseout, confirms that none of the 3 conditions were included in the NSR Authority to Construct issued May 24, 2001. However, the Title V permit was not properly corrected. Table IV-A15 was updated to reflect this change. (VR1#B57, C10)

28. Condition 10574, Part H was revised to make it clear that depressurization gas is to be vented to a control device. This became an issue with S-220 Hot Oil Heater which has liquid filled tubes. Condition 10574 Part H does not apply to the normal liquid draining. Table IV-A10 and A19 were updated to be consistent. (VR1#C11, B58)

29. Condition 19177 was updated to reflect the version issued November 10, 2003 with the Authority to Construct extension for the second phase of the Cogeneration project. This version also includes the changes associated with the end of the commissioning period for Phase I of the project. The other significant revisions include the addition of Part 18a(2), a more stringent NOx BACT for Phase II, and the deletion of the ammonia injection rate monitoring, which was added in error based on an obsolete version of the condition. Tables IV-A22.1 & A22.2 and VII-A22.1 & A22.2 updated to agree with the updates. (VR1#B20, B79, C4, C18, D17 & D18)

30. In Tables IV-A1, A2, A4 and D1, added citations for MACT II, 40 CFR 63 Subpart UUU. (VR1#B4)

31. Added Table IV-K1 and VII-K1 for A57, WWTP Thermal Oxidizer. (EP1#18, 19, 20, 21 & 22)

32. In Tables IV-A8.1 and A8.2, added Subpart J citations that exempt S-16, 17 and 18 from Subpart J since these sources were built prior to 6/11/1973.

33. In Tables IV-A8.1, A8.2 and A9, Regulations 6-305, 6-310, 6-401 and 8-1-110.3 were added. Monitoring was added to Tables VII-A8.1, A8.2 and A9 (EP1#11 & 44)

34. In Tables IV-A4 & A5, added Regulation 6-305, Visible Particles. (EPA#182, EP1#180)

35. In Table IV-X, added Subpart GG and VVV to S-1031 and S-1033. These were inadvertently left out in the previous revision.

36. Revised the effective date of Condition 21233 (NOx Box) in Section IV, VI and VII per 27May04 Administrative Amendment.

37. Revised the effective date of Flare Condition 20806 in Section IV, VI and VII per 27May04 Administrative Amendment.

38. In Table IV-A19, deleted citations 40 CFR 60.44b(l) and 60.44b(l)(1) because S-220 was built before 7/9/1997, and 60.49b(h)(4) because S-220 has a capacity higher than the 250 MMBtu/hr limit of 60.48(b)(1), so is not subject to the emission averaging period. The applicable citations are 40 CFR 60.44b(a) for a NOx limit and 40 CFR 60.48b(b)(1) which requires a continuous monitoring system for NOx. Both of these applicable citations are already in Table IV-A19. (VR1#B13)

39. In Table IV-A20, deleted citations 40 CFR 60.44b(a), 60.44b(a)(l)(1) and 60.44b(e) because S-237 was built after 7/9/1997, and 60.49b(h)(4) because S-237 has a capacity higher than the 250 MMBtu/hr limit of 60.48(b)(1), so is not subject to the emission averaging period. The applicable citations are 40 CFR 60.44b(l)(1) for a NOx limit and 40 CFR 60.48b(b)(1) which requires a continuous monitoring system for NOx. Both of these applicable citations are already in Table IV-A20. (VR1#B16)

40. In Table IV-A22.2, added 40 CFR 60.44b(a)(4) for natural gas firing of the S-1031 and S-1033 Duct Burner, added 40 CFR 60.48b(e)(2) and 60.48b(e)(3) for the NOx CEM span requirement, deleted 40 CFR 60.46b(e), 60.46b(e)(1) and 60.46b(e)(3) because the appropriate citations for S-1031 and S-1033 Duct Burners is 60.46b(f), already shown on Table IV-A22.2, and deleted 60.49b(h)(4) because S-1031 and S-1033 have a capacity higher than the 250 MMBtu/hr limit of 60.48(b)(1), so is not subject to the emission averaging period. Lastly, deleted 60.46(b)(h), 60.46(b)(h)(1) and 60.46(b)(h)(2) because S-1031 and S-1033 are not subject to 60.44(b)(j). The similar changes were also made in Table VII-A22.2 (VR1#B22, B23, B24, D19)

41. In Table IV-J6, replaced the requirements of 8-5-320.4 with 8-5-320.5 since S-72, S-83, S-84 and S-92 Tanks have slotted sampling or gauging wells. (VR1#B61)

42. In Table IV-J14, corrected by deleted text referring to external floating roof tanks. (VR1#B63)

43. In Table IV-J41, deleted 8-5-501.2 because Tank S-208 is not a floating roof tank and is therefore not subject to recordkeeping for seal replacements. (VR1#B69)

44. In Table IV-J27, 8-5-302.1 was replaced with 8-5-302.2 since the tank (S-158) has a side fill submerged fill pipe and is subject to 8-5-302.2 rather than 8-5-302.1, which is for a top fill submerged fill pipe. (VR1#B64)

45. In Table IV-X, added the S-188 and S-189 exemptions from Subpart FF consistent with the requirements shown in Tables IV-H4.1 and H5.1. These sources are exempt because they are vented to the fuel gas system. (VR1#B47)

46. In Table IV-J30, the citations for Subpart Kb and CC were updated to reflect the recently promulgated Subpart Kb. Tank S-230 is now exempt from Subpart Kb because of low vapor pressure. Subpart Kb vapor pressure monitoring was also deleted

from Table VII-J30. (VR1#B65, B66, D37 & D38)

Section VI, Permit Conditions

1. **Conditions 11879, 11882, 11188 and 13319, Parts 4 and 7 were modified to require a minimum thermal oxidizer temperature limit averaged over a consecutive 3-hour period with no allowable temperature excursions. Tables IV and VII-H4.2, H5.2, J36, J37 and J39 were updated to reflect these changes. (EPA#185, 213 and VR1#B37, C2, D28)**

2. **Corrected the tag number of S-1026 C5/C6 splitter (was shown as S-1025) in Condition 10574 in Section VI and in Part 12 shown in Tables IV-A19, D3, D6, H1.1 and J18. (VR1#B15, C1)**

3. **Condition 18043, Parts 2 and 3 were deleted since these fugitive requirements are duplicated in BAAQMD Regulation 8, Rule 18. Tables IV-D3, D5, D6 and D8 were updated to be consistent. (VR1#B28, C3)**

4. **Condition 9296, Parts D8, D9 and D10 were deleted. It is unclear where these Parts originated, but these 3 conditions were in Databank and this was the basis for the first response for this comment (VRC#B38). Recent review of Application 2035, MTBE Phaseout, confirms that none of the 3 conditions were included in the NSR Authority to Construct issued May 24, 2001. However, the Title V permit was not properly corrected. Table IV-A15 was updated to reflect this change. (VR1#B57, C10)**

5. **Condition 10574, Part H was revised to make it clear that depressurization gas is to be vented to a control device. This became an issue with S-220 Hot Oil Heater, which has liquid filled tubes. Condition 10574 Part H does not apply to the normal liquid draining. Table IV-A10 and A19 were updated to be consistent. (VR1#C11, B58)**

6. **Condition 19466 was revised to consistently allow a 45 day duration between the source tests and the submission of the test results to the District. (VR1#C6)**

7. **Condition 19177 was updated to reflect the version issued November 10, 2003 with the Authority to Construct extension for the second phase of the Cogeneration project. This version also includes the changes associated with the end of the commissioning period for Phase I of the project. The other significant revisions include the addition of Part 18a(2), a more stringent NOx BACT for Phase II, and the deletion of the ammonia injection rate monitoring, which was added in error based on an obsolete version of the condition. Tables IV-A22.1 & A22.2 and VII-A22.1 & A22.2 updated to agree with the updates. (VR1#B20, B79, C4, C18, D17 & D18)**

8. **Revised the effective date of Condition 21233 (NOx Box) in Section IV, VI and VII per 27May04 Administrative Amendment. Furthermore, several changes were made in response to the ongoing discussions regarding the NOx Box.**

9. **Revised the effective date of Flare Condition 20806 in Section IV, VI and VII per 27May04 Administrative Amendment.**

Section VII, Monitoring Requirements

1. **In Table VII-Refinery, added two new VOC monitoring requirements from the recently modified Regulation 8, Rule 10. (VR1#D1)**

2. **In Table VII-A6.2, increased the Source Test frequency of the CO Condition 21233, Part 9 limit to semiannual for S-24 and S-26 to be consistent with the requirements of Condition 21233 in Section VI for unit duties greater than 25 MMBtu/hr. (VR1#D5)**

3. **In Tables VII-A8.1 & A9, deleted the second and redundant 12-11-507 monitoring. Valero installed video cameras prior to 1/1/2003 so the first 12-11-507 monitoring citation applies. (VR1#D8)**

4. **In Table VII-A8.2, the 6-301 monitoring requirement was corrected to be consistent with Table IV-A8.2 and Section VI since S-17 is not subject to Condition 20806. (VR1#D9)**

5. **In Tables VII-A10, A11, A12, A15, A16 and A19, corrected the monitoring requirement citation to Condition 21233, Part 8 and increased the frequency to semiannual for these sources with CO CEMs to be consistent with Section VI. (VR1#D12)**

6. **In Table VII-A18, the reference to 21233, Part 4B was deleted to be consistent with Section VI since S-173 is less than 25 MMBtu/hr and not subject to the O2 part of the NOx Box establishment Part 3B. (VR1#D16)**

7. **Condition 19177 was updated to reflect the version issued November 10, 2003 with the Authority to Construct extension for the second phase of the Cogeneration project. This version also includes the changes associated with the end of the commissioning period for Phase I of the project. The other significant revisions include the addition of Part 18a(2), a more stringent NOx BACT for Phase II, and the deletion of the ammonia injection rate monitoring, which was added in error based on an obsolete version of the condition. Tables IV-A22.1 & A22.2 and VII-A22.1 & A22.2 updated to agree with the updates. (VR1#B20, B79, C4, C18, D17 & D18)**

8. **In Table VII-B6, removed the monitoring for 6-301 since S-232 discharges directly into S-233. This is consistent with Condition 19466, Part 3 in Section VI. (VR1#D24)**

9. **Conditions 11879, 11882, 11188 and 13319, Parts 4 and 7 were modified to require a minimum thermal oxidizer temperature limit averaged over a consecutive 3-hour period with no allowable temperature excursions. Tables IV and VII-H4.2, H5.2, J36, J37 and J39 were updated to reflect these changes. (EPA#185, 213 and VR1#B37, C2, D28)**

10. Table VII-I was updated to reflect the recent revision to Regulation 8, Rule 18. (VR1#D29)

11. Revised Table VII-J9 to be consistent with the new S-207 service due to the MBTE Phaseout Project. (VR1#D30)

12. Added Table IV-K1 and VII-K1 for A57, WWTP Thermal Oxidizer. (EP1#18, 19, 20, 21 & 22)

13. In Tables IV-A8.1, A8.2 and A9, Regulations 6-305, 6-310 and 6-401 were added. Monitoring was added to Tables VII-A8.1, A8.2 and A9 (EP1#44)

14. Added monitoring for benzene in waste to Table VII-H3 Wastewater Sewer S-161.

15. Revised the effective date of Condition 21233 (NOx Box) in Section IV, VI and VII per 27May04 Administrative Amendment.

16. Revised the effective date of Flare Condition 20806 in Section IV, VI and VII per 27May04 Administrative Amendment.

17. In Table IV-A22.2, added 40 CFR 60.44b(a)(4) for natural gas firing of the S-1031 and S-1033 Duct Burner, added 40 CFR 60.48b(e)(2) and 60.48b(e)(3) for the NOx CEM span requirement, deleted 40 CFR 60.46b(e), 60.46b(e)(1) and 60.46b(e)(3) because the appropriate citations for S-1031 and S-1033 Duct Burners is 60.46b(f), already shown on Table IV-A22.2, and deleted 60.49b(h)(4) because S-1031 and S-1033 have a capacity higher than the 250 MMBtu/hr limit of 60.48(b)(1), so is not subject to the emission averaging period. The similar changes were also made in Table VII-A22.2 (VR1#B22, B23, B24, D19)

18. In Table VII-J41, the VOC monitoring by BAAQMD Condition 8771, Part 2 was deleted consistent with the condition in Section VI. (VR1#D56)

19. In Table IV-J30, the citations for Subpart Kb and CC were updated to reflect the recently promulgated Subpart Kb. Tank S-230 is now exempt from Subpart Kb because of low vapor pressure. Subpart Kb vapor pressure monitoring was also deleted from Table VII-J30. (VR1#B65, B66, D37 & D38)

20. In Table VII-J41, added a row indicating that S-208 is exempt from Subpart Kb due to the tank size change in the recent promulgated Subpart Kb. (VR1#D39)

Section VIII, Test Methods

1. Added three test methods for the addition of MACT II Subpart UUU to the permit (Table IV-A1, A2, A4 & D1). (VR1#E4)

2. **Deleted visible emission monitoring for 40 CFR 60 Subpart A 60.18(c)(1) since 60.18 is not an applicable requirement. (VR1#E2)**

Section IX, Permit Shield

1. **The Tables were re-numbered to be sequential. (VR1#F2)**

2. **Table IX-A6 was added for Regulation 8-2 applicability to flare sources S-16, S-17, S-18 and S-19. (EP1#11)**

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APPENDIX A
GLOSSARY

ACT
Federal Clean Air Act

APCO
Air Pollution Control Officer

ARB
Air Resources Board

BAAQMD
Bay Area Air Quality Management District

BACT
Best Available Control Technology

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

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAPCOA
California Air Pollution Control Officers Association

CEQA
California Environmental Quality Act

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

CO
Carbon Monoxide

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.

Excluded
Not subject to any District regulations.

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

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

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

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

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

MOP
The District's Manual of Procedures.

NAAQS
National Ambient Air Quality Standards

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

NMHC
Non-methane Hydrocarbons (Same as NMOC)

NMOC
Non-methane Organic Compounds (Same as NMHC)

NOx
Oxides of nitrogen.

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

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

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

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

POC
Precursor Organic Compounds

PM
Particulate Matter

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

Process Unit
For the purpose of start-up and shutdown reporting, a process unit is defined as in 40 CFR Part 60 Subpart GGG: 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.

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.

Start-up
For reporting purposes only, a start-up shall be defined as any of the following; the removal of boundary blinds, first fire to a furnace, or the introduction of process feed to a unit. A start-up only occurs following a shutdown unless it involves a newly constructed process unit.

Shutdown
For reporting purposes only, a shutdown shall be defined as any of the following; there is no process feed to a unit, no furnace fires, or the boundary blinds are installed.

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

SO2
Sulfur dioxide

THC
Total Hydrocarbons (NMHC + Methane)

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

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

TPH
Total Petroleum Hydrocarbons

TRMP
Toxic Risk Management Plan

TSP
Total Suspended Particulate

VOC
Volatile Organic Compounds

Units of Measure:

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

Permit Evaluations for

Application 2035 MTBE Phaseout

Application 3782 Alkylation Expansion

Application 8028 Spare Tail Gas Unit, Phase I

Application 8247 Spare Tail Gas Unit, Phase II

EVALUATION REPORT
VALERO REFINERY
MTBE PHASEOUT PROJECT
APPLICATION 2035, PLANT 12626

INTRODUCTION

In 1996, the refineries had to produce cleaner burning gasolines -- California Air Resources Board (CARB) Phase II gasoline -- to achieve emission reductions from gasoline-fueled vehicles as required by the 1990 amendments to the Federal Clean Air Act and the California Clean Air Act. The reformulated gasoline evaporates less readily, reduces emissions of smog-forming and toxic compounds, and burns more completely. To produce these cleaner burning gasolines, the refiners had to meet tougher fuel specifications for Reid vapor pressure, aromatics, olefins, distillation temperatures (T_{50} and T_{90}), sulfur and benzene. In addition, the refineries were required to blend oxygenated compounds into the gasoline to lower carbon monoxide emissions from the vehicle exhaust. The oxygenated gasolines had to contain at least 2.0 % oxygen content, by weight. All gasolines sold in the San Francisco Bay Area had to meet this requirement starting on November 1, 1992.

Valero Refining Company (henceforth Valero) blended Methyl Tertiary Butyl Ether (MTBE) into their gasoline to meet the required oxygen content. MTBE has one oxygen atom and contains 18.2% oxygen, by weight. To meet the required oxygen level, Valero blended approximately 12% MTBE, by volume, into the gasoline.

In Application number 6968, Valero was authorized to import MTBE to the refinery via ship and to store its product in the S-207 external floating roof storage tank. Later, Valero was approved in Application 9425 to build and operate a MTBE Manufacturing Facility (S-211), which significantly reduce their dependency on imported MTBE to the Benicia Refinery.

The Governor of California has now called for a ban on MTBE because of environmental concerns stemming from groundwater contamination. The refineries have until December 31, 2002 to remove MTBE entirely from the gasoline and replace it with a more environmental friendly oxygenated product. Valero has decided to replace MTBE with ethanol. It has one oxygen atom and contains 34.8% oxygen, by weight. Because of the higher oxygen content, only half as much ethanol as MTBE is needed to meet the 2.0 wt% oxygen level.

Valero has submitted Application #2035 to obtain the necessary Authorities to Construct and Permits to Operate for plant modifications to effect the changeover to ethanol. The project will require modifications to existing processing facilities, such as, pumps, instrumentation, vessel internal hardware, and piping changes. The new operation will not entail any new sources.

Hydrofining Process

Valero is proposing to minimize gasoline sulfur levels. In the hydrofining process, Valero utilizes a catalyst in the presence of hydrogen to remove more than 99% of the sulfur from the processed stream. When the hydrofiner's catalyst is being replaced, the gasoline stream that is being produced has a higher sulfur content. This stream must be segregated and blended sparingly into the gasoline to avoid non-compliance with the sulfur limit. Valero is proposing to store the high sulfur component produced during the shutdown in either S-163 or S-77 storage tank. This product will be recycled back through the hydrofiner after the catalyst is changed out. To insure adequate capacity to handle the additional load, the S-1024 Light Cat Naphtha Hydrofiner (LCNHF) will have the internal trays in its stripper tower modified and an additional recycle pump will be added. These modifications will increase the capacity of the LCNHF from 21 MB/D to 24 MB/D (calendar year average). This increased capacity will be used for the recycled material in need of sulfur removal and any additional material that may require sulfur removal prior to blending. Some modifications will be made to the connections and trays in the existing Cat Naphtha Splitter Tower to insure proper delivery of the high sulfur component to the LCNHF.

Vapor Pressure Minimization

Blending one half as much ethanol into the base gasoline instead of MTBE increases the vapor pressure of the finished motor gasoline. The vapor pressure of the base hydrocarbon stock must be reduced to continue to meet the gasoline RVP specification. Butane is one of the most volatile hydrocarbon components and has been targeted by Valero to be removed in the fractionation process. The saturated pentane will go through an additional fractionation step to remove unwanted butane prior to its storage. This will occur in the existing tower in the Alkylation Unit (S-1007) that is currently used to separate butanes from alkylate. The displaced alkylate will be treated in the existing tower of the MTBE Manufacturing Unit (S-211) which is no longer needed. The internal trays in this larger tower will be modified for the removal of additional butane from the alkylate before it is sent to storage.

MTBE Manufacturing Unit Shut Down and Dimersol Reliability

The MTBE manufacturing process used two feedstocks: a light hydrocarbon containing isobutylene and methanol. Because of the shutdown of the MTBE Manufacturing Unit, the isobutylene feed will be routed to the Alkylation Unit. To accommodate this additional isobutylene feed, some of the current propylene feed will be sent to the existing S-1012 Dimersol Unit. The S-1007 Alkylation Unit and the S-1012 Dimersol Unit will continue to be operated within their historical design rates. Valero has experienced in the past fouling problems in the Dimersol Unit due to corrosion buildup in the heat exchangers. Valero is proposing to replace the tube material in the Dimerol Unit with a mild alloy to improve the system reliability.

Ethanol Blending

A mixture of gasoline/ethanol will readily pick up water as the blended gasoline is transported by pipeline, ultimately resulting in a two-phase product (gasoline plus water). To keep the water out of the finished gasoline, ethanol would need to be blended with the gasoline at the distribution terminal. Thus, Valero will produce a gasoline base stock, called CARBOB, that is formulated to be blended with ethanol at the local truck loading racks just prior to delivery to the service stations. The Benicia Marketing Terminal (Plant #12611) handles about 10-15% of the refinery's gasoline production. Ethanol will be blended into the CARBOB at this site. Application #2391 has been submitted for the necessary modifications at the Benicia Marketing Terminal. For completeness, both applications will be cross referenced, as appropriate.

Valero has an existing truck unloading station (S-209) and a storage tank (S-210) which was used to provide the methanol feed stock to the MTBE Manufacturing Unit (S-211). Since these sources are no longer needed for MTBE production, they will be used to receive and store ethanol prior to blending it into the gasoline. Pumps, piping and instrumentation will be installed to transport and blend the ethanol at the truck racks of the marketing terminal.

The affected equipment based on the above changes for the entire MTBE Phaseout Project is as follows:

Valero Benicia Refinery (Plant #12626)	Modification	Alteration	Condition Changes
S-40 Steam Boiler (Administrative)			
S-77 Floating Roof Tank (Store LCNHF)			
S-163 Floating Roof Tank (Store LCNHF)			
S-207 Mogas/MTBE Storage Tank			yes
S-209 Methanol Unloading Station			yes
S-210 Methanol Tank			yes
S-211 MTBE Production Unit			yes
S-1007 Alkylation Unit		yes	
S-1014 Cat Light Ends Splitter		yes	
S-1024 LCNHF	yes		
S-1012 Dimersol Unit		yes	

Valero Marketing Terminal (Plant #12611)	Modification	Alteration	Condition Changes
S-1 Tank Truck Loading			yes
S-2 Tank Truck Loading			yes

EMISSIONS SUMMARY

Fugitive Emissions

Valero intends to install 265 valves, 6 pumps and 795 flanges (connectors) to be used in light and heavy hydrocarbon services at both facilities. The POC emissions from the additional fugitive equipment were estimated at 0.869 ton/year with 0.571 ton/year attributable to refinery operations and 0.289 ton/year chargeable to the Benicia Marketing Terminal. The emission factors were based on the CAPCOA correlation equations and screening values. The District approved the use of the CAPCOA correlation equations for determining the mass rate of emissions from fugitive equipment during the last plant renewal cycle for Valero. The emissions factors are:

	Average Emission Factor (lb/day/comp)
Valves	0.00249
Pumps	0.25
Flanges/Connectors	0.0034

FUGITIVE EMISSIONS
MTBE PHASEOUT PROJECT

	Valves		Pumps		Flanges/Connectors		
	Count	**TPY**	**Count**	**TPY**	**Count**	**TPY**	**Total**
Benicia Marketing Terminal Plant #12611							
S-1 and S-2 Bulk Loading Station	50	0.023	4	0.183	150	0.093	0.298
Benicia Refinery Plant #12626							
S-211 Alkylate Debutanizer (MTBE Tower)	20	0.009			60	0.037	0.046
S-1007 C-5 Debutanizer	20	0.009			60	0.037	0.046
S-1012 Dimersol Unit	10	0.005			30	0.019	0.023
S-1014 Cat Light End Splitter	10	0.005			30	0.019	0.023
S-1024 LCNHF	20	0.009	1	0.046	60	0.037	0.092
Naphtha Rerun	75	0.034	1	0.046	225	0.140	0.219
Sulfur Analyzer	30	0.014			90	0.039	0.053
Contingency	30	0.014			90	0.056	0.069
						Total	**0.869**

Tank Emissions

There will be a net decrease in POC emissions due to storing ethanol instead of methanol in the S-210 storage tank. The Reid vapor pressure of ethanol is about ½ of that of methanol (2.3 psia ethanol as compared to 4.5 psia methanol). The annual throughput limit for S-210 will remain unchanged (575,000 barrels/day).

Process Units

The modifications made to the internal trays of the S-1014 Cat Naphtha Splitter, S-1024 LCNHF and S-211 Alkylate Debutanizer Tower will not result in any increase in emissions from these units. The throughput capacity for S-1024 LCNHF will increase by an average of 3 MBbl/day. This increase is needed to handle the rerun of elevated sulfur streams stored for reprocessing during periods when the Hydrofiner's catalyst is being replaced. This increase in daily capacity will not debottleneck the refinery. The refinery is limited to processing no more than 135,000 barrels of crude oil per day.

PLANT CUMULATIVE INCREASE

POC: 0 (existing)	+	0.571	(proposed: refinery only)	= 0.571 TPY
NOx: 0 (existing)	+	0.0	(proposed)	= 0.0 TPY
SO2: 0 (existing)	+	0.0	(proposed)	= 0.0 TPY
PM10: 0 (existing)	+	0.0	(proposed)	= 0.0 TPY
TSP: 0 (existing)	+	0.0	(proposed)	= 0.0 TPY
CO: 0 (existing)	+	0.0	(proposed)	= 0.0 TPY

TOXIC RISK SCREEN

This proposed project including the Benicia Marketing Terminal will not emit benzene in amounts at or above its threshold listed in Table 2-1-316. Therefore, a toxic risk screen is not required.

	Lb/year	Trigger Level Lb/year
Benzene	6.61	6.7

BEST AVAILABLE CONTROL TECHNOLOGY

BACT is triggered for POC emissions per Regulation 2, Rule 2 for sources which emit in excess of 10 lbs/day per Section 301.1. For this proposed project involving emissions from fugitive components, BACT is not triggered for the fugitive POC emissions. Nonetheless, all the valves, pumps and flanges/connectors placed in service as a result of the MTBE Phaseout Project will satisfy the BACT requirements.

COMPLIANCE

The internal floating roof storage tank (S-210) holding ethanol should continue to comply with Regulation 8, Rule 5 "Storage of Organic Liquids" including Section 325 which requires welded tanks with zero gap secondary seals. It has liquid mounted primary and secondary seals. The internal floating roof tank (S-210) is subject to the NSPS in subpart kb of 40 CFR 60. It will comply with NSPS since it will be equipped with a continuous liquid mounted primary seal.

The fugitive equipment should comply with the Standards of Regulation 8, Rule 18 for Valves, Pumps and Flanges. The leak standards for valves, pumps and flanges will be 100 ppm, 500 PPM and 100 ppm, respectively.

VALVES -- Most valves will use graphite packing which is the best material available to achieve low emissions in a wide variety of applications. All valves will be required to meet a leak rate of no more than 100 ppm.

PUMPS -- The pumps will be equipped with double mechanical seals and an approved Inspection and Maintenance (I&M) Program to reduce emissions from pump seals. A leak standard of 500 PPM will be required to be met.

FLANGES -- The flanges will use graphite or equivalent designed flange gaskets to reduce POC fugitive emissions. A leak standard of 100 PPM will be required to be met.

The requirements of CEQA have been satisfied through a Negative Declaration granted by the Bay Area Air Quality Management.

The project is over 1000 feet from the nearest school and is therefore not subject to the public notification requirements of Regulation 2-1-412.

This proposed project should not pose a health threat to the general public.

BACT, PSD and NESHAPS are not triggered.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

On May 30, 2001, the Bay Area Air Quality Management, acting as lead agency, approved a Final Negative Declaration for the MTBE Phaseout Project which satisfies the requirements under CEQA. A copy of the Negative Declaration is attached.

OFFSETS

Offsets are required for this proposed project for POC since the plant's emissions are greater than 15 tons per year (Regulation 2-2-302). The offsets required for POC emissions for the entire project are 0.869 TPY [0.571 TPY from the refinery operations and 0.289 TPY from the Benicia Marketing Terminal]. Valero will use contemporaneous POC emissions reduction credits occurring from the shutdown of the MTBE Manufacturing Unit (S-211) and the MTBE shipping operation associated with the MTBE Receiving Tank (S-207). Offsets for S-211 and S-207 were provided in Applications number 9425 and 6968, respectively.

In Application #9425, Valero had to offset 4.95 tons/year of POC emissions to allow them to install and operate the following equipment:

	Fugitives TPY	Equipment TPY	Total
S-209 Methanol Unloading Station	0.19		0.19
S-210 Methanol Tank		0.35	0.35
	0.16		0.16
S-211 MTBE Manufacturing Unit	4.25		4.25
	4.60	0.35	4.95

The offsets required for the project were 5.94 TPY [4.95 x 1.2]. Valero surrendered Banking Certificate #87 holding 72.4 TPY of POC credits to cover this offset obligation. Banking Certificate # 277 was issued back to Valero to cover the unused POC credits.

When the project was actually completed, Valero had underestimated the fugitive emissions count for the MTBE project. Actual emissions from fugitives were 11. 5 tons/year of POC instead of 4.6 tons/year. In accordance with their permit conditions (Condition #9296) which allowed for offset adjustments prior to permit issuance, Valero provided offsets for an additional 8.28 tons/year (6.9 TPY x 1.2) of POC emissions. Valero submitted Banking Certificate 347 having 33.672 TPY of POC credits to satisfy this offset obligation. Banking Certificate #441 was issued back to Valero in the amount of 25.392 to cover the balance.

The final totals for the project were:

	Fugitives TPY	Equipment TPY	Additional Fugitives TPY	Total
S-209 Methanol Unloading Station	0.19		0.22	0.41
S-210 Methanol Tank		0.35		0.35
	0.16		0.35	0.51
S-211 MTBE Manufacturing Unit	4.25		6.33	10.58
	4.60	0.35	6.90	11.56

In Application #6968, Valero had to offset 6.51 tons/year of POC emissions to allow them to install and operate the following equipment to import and store MTBE:

POC EMISSIONS

	Fugitives TPY	Equipment TPY	Total
S-207 MTBE Storage Tank	1.44	1.58	3.02
Associated Ship Emissions		3.48	3.48
	1.44	5.07	6.50

The POC offsets required for S-207 were 7.15 TPY [6.5 x 1.1]. Valero surrendered Banking Certificate #86 which contained 122 tons/year of POC credits. to cover this offset obligation. Banking Certificate # 210 was issued back to Valero to cover the unused POC credits.

As shown in the tables, the shutting down of the MTBE unit (S-211), except for the tower, and the MTBE ship operation will generate more than enough contemporaneous POC emissions reduction credits to offset the increase in POC emissions from the proposed project. The following table shows the POC credits due to Valero due to the phasing out of MTBE.

ALLOWABLE POC CREDITS

Allowed	Shutdown	Baseline tons/year	Adjustments	POC Credit
(S-207) MTBE Tank and Marine Related Emissions	Yes (No Ship Emissions)	3.48 (offset level) (Banking Certificate 86)	0.000[1]	3.48
(S-211) MTBE Production Unit	Yes (No MTBE)	4.25 (Offset level) (Banking Certificate 87)	0.000[2]	4.25
	Yes (More fugitives)	6.33 (Offset level) (Banking Certificate 347)	0.000[2]	6.33
			Total	14.06

[1]There are no regulations that apply to POC emissions from ships and assist tugboats
[2]All fugitive components were equipped with present BACT controls

The allowable POC credits are 14.06 tons. After providing 0.869 tons to offset this project increase which includes the Benicia Marketing Terminal, Valero will have 13.191 tons of POC credits remaining. Valero has requested to receive a banking certificate for the POC credits in excess of those needed to meet their offset obligation. Condition number 1 for S-211 which allowed up to 10.58 TPY of POC emissions has been deleted. Condition number 1 for S-207 has been modified to back out the 3.48 TPY of POC emissions from the ship and to reflect only POC emissions from the storage tank.

Valero has also requested to receive credits for NO_x, SO_2 and PM10 emissions due to the elimination of ship emissions from the importation of MTBE. Since the MTBE Phaseout Project does not involve any increase in these pollutants, Valero would need to submit a formal banking application to the District to bank these emissions.

CONDITIONS

BENICIA REFINERY (PLANT #12626)

S-211 Alkylate Debutanizer at MTBE Unit (Condition 9296)

1. Deleted ~~Total fugitive POC emissions from S-208 shall not exceed 10.58 tons in any rolling 365 consecutive day period. The owner/operator shall submit a revised pump, valve and flange count within 15 days of start up in order to show compliance with this permit condition. If fugitive emissions from this source exceed 4.25 tons/year, then the District may adjust the cumulative increase attributable to this permit application before the issuance of the Permit to Operate.~~

2. Deleted ~~The owner/operator of S-208 shall implement an inspection and maintenance program for all pumps, valves and flanges in accordance with District Regulation 8, Rules 18, 25 and 28.~~

3. Deleted ~~The fugitive equipment shall have a leak concentration not to exceed 500 ppm for valves, 500 ppm for flanges and 1000 ppm for pumps above background (expressed as methane measured at 1 cm) unless the leaks are repaired or minimized no later than 7 days in accordance with Regulation 8, Rules 18, 25 and 28.~~

4. The MTBE unit shall be completely shutdown except for the MTBE tower used to remove butane from the Alkylate as part of the MTBE Phaseout Project. <Basis: Banking Credits>

S-1007 Alkylation Unit
S-1014 Virgin Light Ends Splitter
S-1012 Dimersol Unit
(Condition 18043)

1. Total fugitive POC emissions from the MTBE Phaseout Project at the Benicia Refinery (Plant #12626) shall not exceed 0.571 ton in any rolling 12 consecutive month period. The owner/operator shall submit a revised pump, valve and flange count within 15 days of start up in order to show compliance with this permit condition. If fugitive emissions from this source exceed 0.571 ton/year, then the District may adjust the cumulative increase attributable to this permit application before the issuance of the Permit to Operate. <Basis: Cumulative Increase, Toxics>

2. The owner/operator shall implement an inspection and maintenance program for all pumps, valves and flanges used in this MTBE Phaseout Project at the Benicia Refinery (Plant 12626) in accordance with District Regulation 8, Rule 18. <Basis: Compliance Verification, Periodic Monitoring>

3. The fugitive equipment used in this MTBE Phaseout Project at the Benicia Refinery (Plant #12626) shall have a leak concentration not to exceed 100 ppm for valves, 100 ppm for flanges and 500 ppm for pumps above background (expressed as methane measured at 1 cm) unless the leaks are repaired or minimized no later than 7 days in accordance with Regulation 8, Rules 18. <Basis: RACT, Cumulative Increase, Toxics>

S-1024 Light Cat Naphtha Hydrofiner
(New Conditions to be added to Condition #10574)

1. The total throughput of product at this source shall not exceed 24,000 barrels per day, as averaged over any calendar year. <Basis: Cumulative Increase, Toxics>

2. The total daily throughput of product at this source shall be recorded daily in a District approved log. This record shall be retained for a period of at least five years from date of entry. It shall be kept on site and made available to the District staff upon request. <Basis: Recordkeeping>

S-209 ~~Methanol~~ Ethanol Unloading Station (Condition #9296)

1. The transport trucks shall travel on paved roads at all times inside of this ~~the Exxon~~ Facility. <Basis: Cumulative Increase>

2. All deliveries to S-209 Unloading Station of ethanol methanol shall be from the transport trucks unless the operator ~~Exxon~~ first receive prior written approval from the APCO to use other delivery modes. <Basis: Cumulative Increase, Toxics>

3. Deleted ~~Exxon shall pave 9600 square feet of unpaved/unvegetated surface as a part of this project in advance of any operation of this new facility.~~

4. The total number of truck deliveries of ~~methanol~~ ethanol at this facility ~~Exxon~~ shall not exceed 2920 trucks in any rolling 12 consecutive month period. <Basis: Cumulative Increase>

5. The dispensed ethanol ~~methanol~~ from the transport trucks shall be delivered to the S-210 ~~methanol~~ ethanol tank or any storage tank with equivalent controls. ~~subject to advance written approval by the APCO.~~ <Basis: Cumulative Increase>

6. Total fugitive POC emissions from S-209 shall not exceed 0.41 ton in any rolling 12 consecutive month period. ~~The owner/operator shall submit a revised pump, valve and flange count within 15 days of start up in order to show compliance with this permit condition. If fugitive emissions from this source exceed 0.41 ton/year, then the District may adjust the cumulative increase attributable to this permit application before the issuance of the Permit to Operate.~~ <Basis: Cumulative Increase, Toxics>

7. The owner/operator of S-209 shall implement an inspection and maintenance program for all pumps, valves and flanges in accordance with District Regulation 8, Rules 18 ~~25 and 28~~. <Basis: Compliance Verification, Periodic Monitoring>

8. The fugitive equipment shall have a leak concentration not to exceed 100 ppm for valves, 100 ppm for flanges and 500 ppm for pumps above background (expressed as methane measured at 1 cm) unless the leaks are repaired or minimized no later than 7 days in accordance with Regulation 8, Rules 18~~, 25 and 28~~. <Basis: BACT, Cumulative Increase, Toxics>

9. The total number of truck deliveries of ~~methanol~~ ethanol shall be recorded weekly in a District approved log and totalized monthly. This record shall be retained for a period of at least ~~2~~ 5 years from date of entry. It shall be kept on site and made available to District staff upon request. <Basis: Recordkeeping>

S-210 ~~Methanol~~ Ethanol Tank (Condition #9296)

1. The total throughput of product from S-210 shall not exceed 575,000 barrels of ethanol and/or methanol in any rolling 12 consecutive month period. <Basis: Cumulative Increase, Toxics>

2. Total POC emissions from S-210 Storage Tank, including associated fugitive POC emissions, shall not exceed 0.87 ton in any rolling 12 consecutive month period~~. The owner/operator shall submit a revised pump, valve and flange count within 15 days of start up in order to show compliance with this permit condition. If fugitive emissions from the fugitive equipment exceed 0.16 ton/year, then the District may adjust the cumulative increase attributable to this permit application before the issuance of the Permit to Operate.~~ <Basis: Cumulative Increase, Toxics>

3. The owner/operator of S-210 shall implement an inspection and maintenance program for all pumps, valves and flanges in accordance with District Regulation 8, Rules 18~~, 25 and 28~~. <Compliance Verification, Periodic Monitoring>

4. The fugitive equipment shall have a leak concentration not to exceed 100 PPM for valves, 100 PPM for flanges and 500 PPM for pumps above background (expressed as methane measured at 1 cm) unless the leaks are repaired or minimized no later than 7 days in accordance with Regulation 8, Rules 18~~, 25 and 28~~. <Basis: BACT, Cumulative Increase, Toxics>

5. The S-210 internal floating roof tank shall only store ethanol ~~methanol~~ unless written authorization is received from the APCO allowing the use of another product in advance of any use of such product. <Basis: Cumulative Increase, Toxics>

6. The total monthly throughput of ethanol ~~methanol~~ withdrawn from the S-210 Storage Tank Shall be recorded in a District approved log. This record shall be retained for a period of at least ~~2~~ 5 years from date of entry. It shall be kept on site and made available to District staff upon request.
<Basis: Recordkeeping>

S-40 Steam Boiler (Condition #9296)

1. The firing rate of the S-40 boiler shall not exceed 218 million Btu per hour. <Basis: Cumulative Increase, Regulation 9 , Rule 10>

~~1~~ 2. The steam boiler (S-40) shall be equipped with Low NOx burners and flue gas recirculation. <Basis: BARCT, Regulation 9, Rule 10>

~~2~~ 3. The NOx concentration shall not exceed 30 ppmv, dry, corrected to 3 % oxygen, as averaged ove ra calendar year. <Basis: BARCT>

~~3~~ 4. The CO concentration shall not exceed 400 ppmv, dry, corrected to 3 % oxygen. <Basis: BARCT>

~~4~~ 5. The scrubber system upstream of S-40 Boiler shall have a yearly averaged (calendar year) sulfur concentration not to exceed 65 PPM, by volume. <Basis: BARCT>

~~5~~ 6. Deleted ~~The owner/operator shall conduct a District approved source test no later than 30 days after start up to verify compliance with Conditions number 2 and 3. All source test shall be done in accordance with the District's Manual of Procedures. Exxon shall install all necessary source test ports, subject to the approval of the Manager of Source Test in the District Technical Section, prior to any operation of these sources. The results shall be delivered to the District no later than 30 days from the date of test.~~

~~6~~ 7. The owner/operator ~~Exxon~~ shall maintain daily records, in a District approved log, of the sulfur concentration required in Condition number 4. These records shall be retained for a period of at least ~~2~~ 5 years from date of entry. The logs shall be kept on site and made available to District staff upon request. <Basis: Recordkeeping>

S-207 Mogas/Components Storage Tank (Condition #10797)

1. The total release of emissions from this S-207 Storage tank ~~project for delivery and storage of MTBE, which includes the cargo ships and tugs in District waters,~~ shall not exceed 4.62 tons of POC emissions ~~–~~in any rolling 365 consecutive day period the following limit: <Basis: Cumulative Increase, Toxics>

~~Pollutant Tons~~
~~NOx 36.7~~
~~CO 3.7~~
~~POC 8.1~~
~~SO2 9.5~~
~~PM10 1.6~~

2. Deleted ~~The total release of POC emissions from this S-207 MTBE project shall not exceed 140 pounds in any rolling 24 consecutive hour period. This POC total is defined as the sum of all project-related emissions from: (a) the storage tank; (b) valves, pumps and flanges (fugitive emissions); and (c) the cargo ships and tugs in District waters, assist tugs, tugs during maneuvering and (d) transferring of the MTBE from the cargo carrier to the S-207 Receipt Tank.~~

3. The owner/operator of S-207 shall implement an inspection and maintenance program for all pumps, valves and flanges associated with the land-based aspects of this project in accordance with District Regulation 8~~, Rules 18, 25 and 28~~. < Basis: Compliance Verification, Periodic Monitoring>

4. The S-207 External Roof Storage Tank shall store ~~MTBE and/or~~ mogas/components only. <Basis: Cumulative Increase, Toxics>

5. Deleted ~~The total throughput of MTBE at S-207 shall not exceed 5,800,000 barrels in any rolling 365 consecutive day period.~~

6. The total throughput of mogas/components at S-207 shall not exceed 16,936,400 barrels in any rolling 365 consecutive day period. <Basis: Cumulative Increase, Toxics>

7. The total daily throughput of ~~MTBE and~~ mogas/components withdrawn from the S-207 Storage Tank shall be recorded in a District approved log. This record shall be retained for a period of at least ~~two~~ five years from date of entry. It shall be kept on site and made available to the District staff upon request. <Basis: Recordkeeping>

8. Deleted ~~The owner/operator shall maintain daily records (calendar day), in a District approved log, for: (1) the total number of MTBE deliveries by ship and barge, (2) ship and tug boat fuel usage (actual or estimated if not logged in) in District waters attributable to the S-207 project only, (3) type of fuel, (4) hours of ship operation in District waters attributable to the S-207 project only, (5) size capacity of ship and barge in DWT. In addition, the daily throughput of MTBE transferred at the Exxon dock from the cargo ship or barge to S-207 shall be recorded~~

~~in a District approved log. All records shall be retained for a period of at least two years from the date of entry. This log shall be kept on site and made available to the District on request.~~

~~If a cargo carrier for this S-207 project calls on multiple ports, such as in Martinez, Exxon will be charged for all round trip emissions from the port to the existing Exxon dock in Benicia and back to port. For the purposes of record keeping, Exxon need to maintain records only for the portion of the project chargeable to their operation.~~

9. Deleted ~~On the day of MTBE delivery at Exxon and each day of MTBE transfer from the cargo carrier to S-207, the owner/operator shall determine, using a District approved calculation procedure, the total POC emissions from this project to verify compliance with Conditions Number 2. These daily totals shall be entered into the log and shall be summarized monthly. A Quarterly summary report shall be submitted to the District by the 10th day of the month following the close of the quarter. All records shall be retained for at least two years from date of entry. This log shall be kept on site and made available to the District staff upon request.~~

The conditions for the Benicia Marketing Terminal are shown for completeness purposes only. These changes will be handled in Application #2391.

Valero Marketing Terminal (Plant #12611)
Condition #18042

S-1 Tank Truck Loading
S-2 Tank Truck Loading

1. ~~Exxon's vapor recovery system shall not emit into the atmosphere more than~~ S-1 and S-2 shall not be operated unless abated A-1 Carbon Adsorption Vapor Recovery System. Abated emissions from S-1 and S-2 shall not exceed 7.2 grams of precursor organic compounds per cubic meter (0.06 lbs per 1000 gallons) of organic loaded.
<Basis: Cumulative Increase, Toxics>

2. The total abated daily precursor organic compound emissions from S-1 and S-2 ~~Exxon's vapor recovery system~~ shall not exceed 56 lbs per day including ethane but excluding fugitive emissions. <Basis: Cumulative Increase, Toxics>

3. Owner/operator ~~Exxon~~ shall install a continuous hydrocarbon emissions monitor at the exhaust outlet of the vapor recovery system. This detector shall continuously measure hydrocarbon concentration in PPM as C4. This monitor shall be coupled to a 2-stage alarm system. The first stage shall sound an alarm when the exhaust concentration reaches 8000 PPM (as C4). The second stage shall shut down the loading rack when the exhaust concentration reaches 10,000 PPM (as C4). <Basis: Monitoring>

4. The average hydrocarbon concentration shall not exceed 2600 PPM (as C4) at the exhaust outlet of the vapor recovery system for the entire cycle of each carbon bed. <Basis: Cumulative Increase>

5. Owner/operator ~~Exxon~~ shall install a continuous strip chart recorder to record the temperature of each of the carbon beds. If the temperature exceeds 195^{o}F, an alarm shall sound and no gasoline loading shall occur. <Basis: Monitoring, Public Safety, Public Nuisance, Odors, Cumulative Increase, Toxics>

6. The monitoring equipment required in Condition #3 shall be subject to the procedure set forth in District Regulation 1 Section 522 with the exception of Regulation 1-522.5. All monitors shall be calibrated weekly. <Basis: Monitoring Accuracy>

7. Combined ~~Exxon's~~ average daily throughput of S-1 and S-2 shall not exceed the lesser of: (a) 270,000 gallons per hour nor 950,000 gallons per day, or; (b) the CARB certified terminal gasoline limits. <Basis: Cumulative Increase, Toxics>

8. All equipment at this facility, which is subject to Regulation 8-33, shall be maintained in good operating conditions at all times. The maintenance of the vapor recovery unit shall be conducted in accordance with current manufacturer's recommendations. <Basis: RACT>

9. All monitoring and maintenance records required for the vapor recovery system at this facility, which is the subject to Regulation 8-33, shall be kept on site for ~~two~~ five years from the date of entry and made available to the APCO upon request. <Basis: recordkeeping>

10. No gasoline or ethanol loading shall occur when the temperature on any of the carbon beds reaches 195^{o}F. At such time, the vapor recovery unit shall be shut down. Owner/operator ~~Exxon~~ shall follow the "High Carbon Bed Temperature Shutdown" procedures as set forth in the current manufacturer's operating manual. <Basis: Monitoring, Public Safety, Public Nuisance, Odors, Cumulative Increase, Toxics>

11. Total fugitive POC emissions installed as part of the MTBE Phaseout Project at S-1 and S-2 shall not exceed 0.298 ton in any rolling 12 consecutive month period. The owner/operator shall submit a revised pump, valve and flange count within 15 days of start up in order to show compliance with this permit condition. If fugitive emissions from this source exceed 0.298 ton/year, then the District may adjust the cumulative increase attributable to this permit application before the issuance of the Permit to Operate. <Basis: Cumulative Increase, Toxics>

12. The owner/operator of S-1 and S-2 Bulk Truck Loadout Terminal shall implement an inspection and maintenance program for all pumps, valves and flanges in accordance with District Regulation 8, Rule 18. <Basis: Compliance Verification, Periodic Monitoring>

13. The fugitive equipment installed for the MTBE Phaseout Project shall have a leak concentration not to exceed 100 PPM for valves, 100 PPM for flanges and 500 PPM for pumps above background (expressed as methane measured at 1 cm) unless the leaks are repaired or minimized no later than 7 days in accordance with Regulation 8, Rules 18. <Basis: RACT, Cumulative Increase, Toxics>

AUTHORITY TO CONSTRUCT

I recommend that conditional Authorities to Construct be granted to Valero for the modifications and alterations indicated herein to phaseout of MTBE at the Benicia Refinery:

Valero Benicia Refinery (Plant #12626)

S-40 Steam Boiler (Administrative)
S-77 Floating Roof Tank (Store LCNHF)
S-163 Floating Roof Tank (Store LCNHF)
S-207 MTBE/Mogas Storage Tank: to be changed for Mogas only
S-209 Methanol Unloading Station: to be changed to ethanol station
S-210 Methanol Tank: to be changed to store ethanol
S-211 MTBE Production Unit: To be shutdown except for main tower
Modification to internal trays
S-1007 Alkylation Unit: Route isobutylene feed to Alkylate Unit
S-1014 Cat Light Ends Splitter: Modifications to connectors and trays
S-1024 LCNHF: modify internal trays on stripper tower
S-1012 Dimersol Unit: Changes to optimize unit's performance
Replace tube material in heat exchanger with mild alloy

Banking Certificate

I recommend that a banking certificate be issued to Valero for the POC emissions reduction occurring as a result of the MTBE phaseout at the time the credits are realized due to shutdowns and other modifications. The preapproved POC credits eligible to be banked at a future date when the project has been fully implemented are:

13.191 TPY

____
Douglas Wayne Hall
Supervising Air Quality Engineer

EVALUATION REPORT

VALERO REFINING CO. - CALIFORNIA

APPLICATION #3782

BACKGROUND

In 1996, the refineries had to produce cleaner burning gasoline -- California Air Resources Board (CARB) Phase II gasoline -- to achieve emission reductions from gasoline-fueled vehicles as required by the 1990 amendments to the Federal Clean Air Act and the California Clean Air Act. The reformulated gasoline evaporates less readily, reduces emissions of smog-forming and toxic compounds, and burns more completely. To produce these cleaner burning gasolines, the refiners had to meet tougher fuel specifications for Reid vapor pressure, aromatics, olefins, distillation temperatures (T_{50} and T_{90}), sulfur and benzene. In addition, the refineries were required to blend oxygenated compounds into the gasoline to lower carbon monoxide emissions from the vehicle exhaust. The oxygenated gasolines had to contain at least 2.0 % oxygen content, by weight. All gasoline sold in the San Francisco Bay Area had to meet this requirement starting on November 1, 1992.

Valero Refining Company (henceforth Valero) blended Methyl Tertiary Butyl Ether (MTBE) into their gasoline to meet the required oxygen content. MTBE has one oxygen atom and contains 18.2% oxygen, by weight. To meet the required oxygen level, Valero blended approximately 12% MTBE, by volume, into the gasoline.

The Governor of California has now called for a ban on MTBE because of environmental concerns stemming from groundwater contamination. The refineries have until December 31, 2002 to remove MTBE entirely from the gasoline and replace it with a more environmental friendly oxygenated product. Valero has decided to replace MTBE with ethanol. It has one oxygen atom and contains 34.8% oxygen, by weight. Because of the higher oxygen content, only half as much ethanol as MTBE is needed to meet the 2.0 wt% oxygen level.

Valero submitted Application #2035 to obtain the necessary Authorities to Construct and Permits to Operate for plant modifications to effect the changeover to ethanol. The Authority to Construct was granted on May 24, 2001. The project requires modifications to existing processing facilities, such as, pumps, instrumentation, vessel internal hardware, and piping changes. This operation is still under construction and will not entail any new sources.

INTRODUCTION

Valero has submitted this application, assigned number 3782, to make minor changes in their operation to produce higher quantities of CARBOB (base gasoline stock prior to blending MTBE or Ethanol). This increased production will be accomplished by diverting about 2000 B/D of existing propylene feed from the Dimersol Unit (S-1012) to the Alkylation Unit (S-1007). Also, Valero would like the flexibility to feed imported isobutane (via rail cars) to the Alkylation Unit as the market dictates. A sulfuric acid catalyst will be used to convert olefin streams consisting of propylenes and butylenes into gasoline blending components.

Alkylate production will increase from a maximum annual design rate of about 18,500 B/D to 22,800 B/D. The process will require additional cooling to accommodate higher Alkylate production rates. Additional steam will be needed for fractionation heat. The steam will come from existing permitted and offset boilers (Sources S-237, S-1031 and S-1033) at Valero. The new equipment for this proposed project includes:

1. Additional exchangers, pumps, piping and instrumentation to install an acid wash section.

2. Additional piping to allow propylene and butylenes segregation.

3. Alterations to the Alkylation (S-1007) and Cat Light Ends cooling water system. The cooling water systems do not contain hydrocarbons. This project will involve a minor modification to an existing operation that will accommodate a higher Alykalate production rate.

This minor modification will not result in the emissions of any regulated air pollutant not previously emitted in a quantity that would cause the source to fail a toxic risk screen.

Upstream process units will not be affected by this project.

The alkylate will continue to be stored at the S-78 External Floating Roof Tank. The alkylate will then be blended into several existing Mogas storage tanks (S-79, S-80, S-82, S-84, S-86, S-92 and S-97) which have unused capacities. Rail traffic due to the existing importing of isobutane should not increase.

EMISSIONS

The proposed project is estimated to require the installation (net count) of about: (a) 1 pump, (b) 100 valves, (c) 200 flanges/connectors and (d) 2 pressure relief valves. The emissions from these additional fugitive components are estimated to be 0.643 pound/day (235 pounds/year, 0.118 TPY). See attached table.

The project will result in a net increase in Alkylate throughput at S-78 External Floating Roof Tank (TK-1739). The increase will result in more product turnovers. VOC emissions were estimated using EPA Tanks 4.0 equivalent calculation methodology. The VOC emissions from S-78 are estimated to increase by 13 pounds per day. See attachment.

The acid wash section will include additional heat exchangers, pumps and associated piping. The only emissions associated with the acid wash section are two pumps in hydrocarbon service. The VOC emissions are estimated to be about 0.27 pounds per day (99 lbs/yr).

Alkylate will be blended into the Mogas Tanks (S-79, S-80, S-82, S-84, S-86, S-92 and S-97). The throughput capacities for these tanks will not be exceeded. It should be noted that Dimate and LPG sales are reduced when Alkylate production is increased. The amount of Dimate blended into the affected Mogas Tanks will decrease when Alkylate is increased.

CUMULATIVE INCREASE

235 (fugitives) + 13 (tank) + 99 (fugitives) = 347 lb/year (0.174 TPY)

	Existing (TPY)		Proposed (TPY)		Total (TPY)
POC	**0.0**	**+**	**0.174**	**=**	**0.174**

TOXICS

This project does not trigger a toxic risk screen per Table 2-1-413. The toxic contaminant of concern for this proposed project is benzene. Alkylate contains about 0.3% benzene, by weight.

347 lb/yr x 0.003 lb Benzene = 1.04 lb/yr Benzene

Toxic trigger level is 6.7 lb/yr Benzene

COMPLIANCE

The alterations to the S-1007 Alkylation Unit which include mostly additional fugitive components should continue to be in compliance with applicable governing rules and regulations. The additional fugitive components should comply with Regulation 8, Rule 18. The increase in VOC emissions from the fugitive components (valves, flanges, pressure relief valves, pumps) including the acid wash section will be less than 1 pound/day.

The Alkylate Storage Tank (S-1007) will continue to comply with Regulation 8, Rule 5.

The Mogas Tanks (S-79, S-80, S-82, S-84, S-86, S-92 and S-97), where the additional Alkylate will be blended to form finished gasoline, will continue to comply with Regulation 8, Rule 5 requirements.

These proposed changes are not within 1000 feet of a school. Therefore, it is not subject to the public notification requirements of Regulation 2-1-412.

This application is considered to be categorical exempt per District Regulation 2-1-312.6:

- Permit applications relating to minor alterations of existing facilities' equipment or sources involving negligible or no expansion of use beyond that previously existing.

BACT, NSPS, NESHAPS and PSD are not triggered.

OFFSETS

Because Valero is a major facility for POC emissions, offsets will be provided in accordance with Regulation 2-2-302. The offsets needed are: 0.174 TPY x 1.15 = 0.200 TPY

The offsets will come out of Certificate 682, which was surrendered recently to cover the offset obligation for the Cogeneration Project (Application 2488 and 2695). After offsets were provided a balance of 7.147 tons/year was refundable back to Valero. Valero has requested that 0.2 TPY be used out of the remaining balance for that certificate to offset this project emission. Valero will be issued a Banking Certificate for the balance of 6.947 TPY POC [14.769 TPY POC Certificate 682 – 7.622 TPY Cogeneration Project (Application #2488 and #2695) – 0.2 TPY (Application #3782)].

CONDITIONS

MAJOR FACILITY REVIEW PERMIT

The conditions for the Alkylation Unit (S-1007) are found in condition #10574. However, there is no specific condition that limits the throughput for the Alkylation Unit. A condition was added (number 51) to limit the daily throughput to no more than 22,800 barrels. It reads as follows:

51. The total daily throughput of alkylate from the Alkylation Unit (S-1007) shall not exceed 22,800 barrels. (Basis: BACT, Cumulative Increase)

The capacity limitation in the draft Title V permit is 18,500 barrels per day. Per this permit application, it will be changed prior to going out on public comment to 22,800 barrels per day.

FUGITIVE EMISSIONS

The fugitive components in Phase III of the Clean Fuels Project will be subject to the same conditions found in Condition #10574 for the Clean Fuels Project (Application #10392) in Phase II which includes the Alkylation Unit (S-1007). Condition #10574 is attached. For this project, another condition was added (number 52) to allow for an adjustment in the final fugitive count beyond the project's estimated quantity. The condition reads as follows:

52. The Alkylate Production Project in Application 3782, when installed shall consist of no more than 100 valves, 200 connectors/flanges, 2 pressure relief valves and 3 pumps. The POC emissions from the entire project shall not exceed 0.2 ton/year. The annual mass limit for POC may be adjusted based on final fugitive component count. Any additional POC offsets required due to a larger fugitive component count would need to be provided prior to permit issuance. (Basis: Cumulative Increase Offsets)

RECOMMENDATION

I recommend that Valero Refining Company be granted a conditional Authority to Construct to make piping changes and other alterations to increase daily production of alkylate at the Alkylation Unit (S-1007).

By: ______________________________ Date:

Douglas W. Hall
Supervising Air Quality Engineer

EVALUATION REPORT
VALERO BENICIA REFINERY
SPARE TAIL GAS HYDROGENATION REACTOR
APPLICATION 8028, PLANT 12626

BACKGROUND

The Valero Benicia Refinery (Valero) operates a tail gas treatment process that abates the discharge vapors from the Sulfur Plants. This process consists of

S-1 Claus Sulfur Plant A, 480 short tons/day (VIP rate), 58,400 short tons/yr (Title V)
S-2 Claus Sulfur Plant B, 480 short tons/day (VIP rate), 58,400 short tons/yr (Title V)
A-24 Tail Gas Hydrogenation unit (Beavon Process) consisting of a Reducing Gas Generator, Hydrogenation Reactor, and Waste Heat Boiler
A-56 Flexsorb Absorption Unit, including an amine Adsorption Unit and Regenerator. The H_2S containing acid gas is recycled back to the Claus Units.
P-50 Cleaned Tail Gas discharge from Flexsorb unit.

The trains (not currently represented properly in Databank) are as follows:
S1,A24,A56,P50 and
S2,A24,A56,P50.

This process works well discharging vapors that comply with District regulations. However, this unit is critical to the operation of the refinery. Since there is no alternative treatment, any failure of the unit can result in a refinery shut down. Normally, periodic refinery turnarounds are capable to address any maintenance or reliability issues with critical units such as this tail gas treatment system. However, the catalyst in the S-24 Hydrogenation Reactor has two to three year life, which is shorter than the target refinery turnaround cycle.

This application if for the installation of a spare hydrogenation unit:

A-62 Spare Tail Gas Hydrogenation Unit with Reactor and Waste Heat Boiler

Originally, this application was submitted as a complete 100% spare to the existing A-24 unit. Furthermore, the application requested approval under the Accelerated Permit Program because mandatory recertification of the unit's waste heat boiler requires a unit shutdown in February 2004. The applicant tried to obtain a deferral of the boiler recertification to avoid a special shutdown and a compressed construction schedule. However, this option was rejected.

Upon review of the original application, it was determined that the spare unit did not qualify for the Accelerated Permit Program because there is an increase in emissions. When the spare unit is brought online, there is an 8 to 12 hour transition period where both Reducing Gas Generators will be operating concurrently as the spare unit comes up to temperature. The Reducing Gas

Generator (aka the Combustor) burns natural gas so the combined combustion products from both units would result in a net increase of emissions. This transition period to the spare unit is expected infrequently (every 2 to 3 years), and according to the applicant, the emission increase would be small. However, the increase is real (and currently undefined), preventing qualification for the Accelerated Permit Program.

To resolve this issue, the applicant agreed to remove the Reducing Gas Generator from the application, leaving only the Hydrogenation Reactor and the Waste Heat Boiler. Tie-ins for a future Reducing Gas Generator would be provided, but the installation would be the subject of a future application. Until the installation of the spare Reducing Gas Generator, the existing fired equipment will be used at 100% duty and manifolded to both the existing reactor and the spare reactor. With this change to the application, any concurrent operation of the primary and spare unit will not result in an increase in emissions. Consequently, on August 13, 2003, the District granted approval of equipment installation and operation under the Accelerated Permit Program.

EMISSIONS SUMMARY

There are no changes in emissions due to this application. The design and performance of the spare equipment is identical to the existing unit.

PLANT CUMULATIVE INCREASE

There are no net changes to the plant cumulative emissions.

TOXIC RISK SCREEN

This proposed throughput change would not emit toxic compounds in amounts different that previously emitted. Therefore, a toxic risk screen is not required.

BEST AVAILABLE CONTROL TECHNOLOGY

BACT is triggered for new or modified sources that emit criteria pollutants in excess of 10 lbs/day. However, Regulation 2-1-234 defines a modified source as one that results in an increase in daily or annual emissions of a regulated air pollutant. For this application, there is no change in emissions. Therefore, BACT does not apply.

PLANT LOCATION

According to the SCHOOL program, the closest school is Semple Elementary, which is just over one mile from the facility.

COMPLIANCE

The installation of this spare equipment will not change the compliance for the Sulfur Plants S-1 and S-2. Tail gas emissions from S-1 and S-2, abated by either A-24 or A-62, then by A-56, will comply with Regulations 6-301, 6-310 and 6-330:

6-301 **Ringelmann No. 1 Limitation:** Except as provided in Sections 6-303, 6-304 and 6-306, a person shall not emit from any source for a period or periods aggregating more than three minutes in any hour, a visible emission which is as dark or darker than No. 1 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree.

6-310 **Particulate Weight Limitation:** A person shall not emit from any source particulate matter in excess of 343 mg per dscm (0.15 gr. per dscf) of exhaust gas volume.

6-330 **Sulfur Recovery Units:** A person shall not emit from any operation manufacturing sulfur, using as a principal raw material any sulfur-containing material, any emission having a concentration of SO_3 or H_2S0_4, or both, expressed as 100% H_2S0_4, exceeding 183 mg dscm (0.08 gr. dscf) of exhaust gas volume.

The closest school is over a mile from the facility, so the Public Notice requirements of Regulation 2-1-214 do not apply.

Toxics, CEQA, NESHAPS, BACT, Offsets and NSPS do not apply.

CONDITIONS

Existing Conditions 125 and 126 will be modified as follows:

COND# 125 ---

Valero Refining Company – California
3400 E. Second Street
Benicia, Ca 94510
Application 8028
S-1 Sulfur Plant A
Previous Applications: 26227(1977), 26878(1979), 29808 (1984), 17850(1997)

1. Reasonable access to 24 hour sulfur production data shall be provided by the owner/operator whenever the APCO or his designated representative performs compliance determination on the Sulfur Recovery Unit (SRU), Tail Gas Clean-up Unit and main stack.

2. The owner/operator shall install the best available H2S monitoring system ~~shall be installed at~~on the Tail Gas Clean-up Unit exhaust stack,

subject to approval by the APCO.

3. Except during upset conditions, the owner/operator shall not open motor operated valve (MOV-001), which allows Tail Gas from S-1 to flow to the incinerator (F-1302A; A-14), ~~shall not be open~~ when either of the sour gas feed valves (F002, F004) to source (S-1) are open. A closed block valve or blind in the pertinent lines shall be considered sufficient to fulfill this requirement.

4. Except during upset conditions, the owner/operator shall route the tail gases from the S-1 Sulfur Recovery Unit ~~shall be routed~~ to ~~and cleaned up by~~ the Beavon and Flexsorb SE Tail Gas Treatment Units (A-24, A-62 and A-56). The recovered hydrogen sulfide shall be returned to the S-1 and/or S-2 SRU for recovery as elemental sulfur.

list condition NUMBER >> 126

COND# 126 ---

Valero Refining Company – California
3400 E. Second Street
Benicia, Ca 94510
Application 8028
S-2 Sulfur Plant B
Previous Appications: 26227(1977), 26878(1979), 29808 (1984), 17850(1997)

1. Reasonable access to 24 hour sulfur production data shall be provided by the owner/operator whenever the APCO or his designated representative performs compliance determination on the Sulfur Recovery Unit (SRU), Tail Gas Clean-up Unit and main stack.

2. The owner/operator shall install the best available H2S monitoring system ~~shall be installed at~~on the Tail Gas Clean-up Unit exhaust stack, subject to approval by the APCO.

3. Except during upset conditions, the owner/operator shall not open motor operated valve (MOV-003), which allows Tail Gas from S-2 to flow to the incinerator (F-1302B; A-15), ~~shall not be open~~ when either of the sour gas feed valves (F052, F054) to source S-2 are

open. A closed block valve or blind in the pertinent lines shall be considered sufficient to fulfill this requirement.

4. Except during upset conditions, the owner/operator shall route the tail gases from the S-2 Sulfur Recovery Unit ~~shall be routed~~ to ~~and cleaned up by~~ the Beavon and Flexsorb SE Tail Gas Treatment Units (A-24, A-62 and A-56). The recovered hydrogen sulfide shall be returned to the S-1 and/or S-2 SRU for recovery as elemental sulfur.

Condition 18344 is the condition currently shown as current in Databank for S-1 and S-2. This condition will be archived.

COND# 18344 --

1. Deleted (Application #3902, 1/02)
2. Deleted (Application #3902, 1/02)

Condition 19466 is the future condition for S-1 and S-2. This condition is the Title V monitoring condition. The pertinent parts are highlighted.

COND# 19466 --

VALERO REFINING COMPANY
TITLE V CONDITIONS

1. The Permit Holder shall conduct an annual District-approved source test on the S-1 and S-2 Claus Units to demonstrate that 95% of the H2S in the refinery fuel gas is removed and recovered on a refinery-wide basis and 95% of the H2S in the process water streams is removed and recovered on a refinery-wide basis AND 95% of the ammonia in the process water stream is removed. The test results shall be provided to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. The test shall include sampling of the inlet and outlet of the fuel gas scrubber and sour water stripper towers. [Basis: Regulation 9-1-313.2]

2. The Permit Holder shall conduct an annual District-approved source test on the S-188 CPS Units to demonstrate that the combined collection/destruction efficiency of the <A- > is no less than 95%, by weight, for VOC. The test results shall be provided

to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. These records 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: Regulation 8-8-302.3]

3. The permit holder shall monitor and record on a monthly basis the visible emissions from Sources S-1, S-2, S-5, S-6, S-8, S-10, S-11, S-176, S-232 and S-233 to demonstrate compliance with Regulation 6-301 (Ringlemann 1 or 20% opacity). These records 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: Regulation 6-301]

4. The permit holder shall monitor and record on a semi-annual basis the visible emissions from the S-231 and S-236 to demonstrate compliance with Regulation 6-301 (Ringlemann 1 or 20% opacity). These records 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. [BAAQMD 6-301]

5. The emissions from the S-3 and S-4 CO Boilers shall be abated by the A-1 through A-5 Electrostatic Precipitators and exhausted through the main stack (P-1). [Basis: Regulation 6-301 and Regulation 6-304].

6. The permit holder shall perform an annual source test on Sources S-1, S-2, S-5, S-6, S-8, S-10, S-11, S-12, S-176, S-232, S-233 and S-237 to demonstrate compliance with Regulation 6-310 (outlet grain loading no greater than 0.15 grain/dscf). The test results shall be provided to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. These records 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: Regulation 6-310]

7. The permit holder shall perform an annual source test on Sources S-8, S-10, S-11, S-12, S-176, S-232 and S-233 to demonstrate compliance with Regulation 6-

310.3 (outlet grain loading no greater than 0.15 grain/dscf @ 6% oxygen). The test results shall be provided to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. These records 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: Regulation 6-310.3]

8. The Permit Holder shall perform an annual source test on S-1 and S-2 to determine compliance with Regulation 6-330 (Outlet grain loading not to exceed 0.08 grain/dscf of SO3 and H2SO4). The test results shall be provided to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. These records 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: Regulation 6-330]

9. The Permit Holder shall perform an annual source test on Sources S-5, S-6, S-8, S-10, S-11, S-12, S-176, S-232, S-233 and S-237 to demonstrate compliance with Regulation 6-311 (PM mass emissions rate not to exceed 4.10P0.67 lb/hr). The test results shall be provided to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. These records 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: Regulation 6-311]

10. The Permit Holder shall conduct a District-approved source test on an semi-annual basis on Sources S-7, S-20, S-23, S-24, S-26, S-30, S-31, S-32, S-33, S-34, S-35, S-38 and S-39 to demonstrate compliance with Regulation 9-10-305 (CO not to exceed 400 ppmv, dry, at 3% O2, operating day average. The test results shall be provided to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. These records 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: Regulation 9-10-305]

11. The Permit Holder shall conduct a semi-annual District-approved source test on Sources S-43, S-44 and S-46 to demonstrate compliance with Regulation 9-9-301.1 (NOx not to exceed 55 ppmv, dry, at 15% O2, fired on refinery fuel gas. The test results shall be provided to the District's Compliance and Enforcement Division and the District's Permit Services Division no less than 30 days after the test. These records 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: Regulation 9-9-301.1]

12. The VOC emissions from the S-159 Lube Oil Reservoir shall be abated by the S-36 Boiler. [Basis: Cumulative Increase]

13. The VOC emissions from S-167 and S-168 Seal Oil Spargers shall be vented in a closed system to the fuel gas header to be introduced into the refinery fuel gas stream. [Basis: Cumulative Increase]

RECOMMENDATION

It is recommended that an Authority to Construct be waived and a Permit to Operate be granted to Valero for:

A-62 Spare Tail Gas Hydrogenation Unit with Reactor and Waste Heat Boiler

Arthur P. Valla
Air Quality Engineer

Date

EVALUATION REPORT
VALERO BENICIA REFINERY
SPARE TAIL GAS REDUCING GAS GENERATOR
APPLICATION 8427, PLANT 12626

BACKGROUND

The Valero Benicia Refinery (Valero) operates a tail gas treatment process that abates the discharge vapors from the Sulfur Plants. This process consists of

S-1 Claus Sulfur Plant A, 480 short tons/day (VIP rate), 58,400 short tons/yr (Title V)
S-2 Claus Sulfur Plant B, 480 short tons/day (VIP rate), 58,400 short tons/yr (Title V)
A-24 Tail Gas Hydrogenation unit (Beavon Process) consisting of a Reducing Gas Generator, Hydrogenation Reactor, and Waste Heat Boiler
A-56 Flexsorb Absorption Unit, including an amine Adsorption Unit and Regenerator. The H_2S containing acid gas is recycled back to the Claus Units.
P-50 Cleaned Tail Gas discharge from Flexsorb unit.

The trains (not currently represented properly in Databank) are as follows:
S1,A24,A56,P50 and
S2,A24,A56,P50.

This process works well discharging vapors that comply with District regulations. However, this unit is critical to the operation of the refinery. Since there is no alternative treatment, any failure of the unit can result in a refinery shut down. Normally, periodic refinery turnarounds are capable to address any maintenance or reliability issues with critical units such as this tail gas treatment system. However, the catalyst in the S-24 Hydrogenation Reactor has two to three year life, which is shorter than the target refinery turnaround cycle.

To avoid shutting down the refinery in the event of failure of the tail gas treatment system, the applicant has proposed to install an identical spare (backup) unit. The spare will consist of a hydrogenation Unit with reactor, waste heat boiler and a reducing gas generator unit. This proposed project was broken up into two phases. Phase I includes the hydrogenation Unit with reactor and the waste heat boiler, which was permitted in Application #8028. This application is for the permitting of the equipment in Phase II:

A-62 Spare Tail Gas Reducing Gas Generator, natural gas fired, 9.1 MMBtu/hour

When this spare unit is brought online, there is an 8 to 12 hour transition period where both Reducing Gas Generators (existing and spare) will be operating concurrently as the spare unit comes up to temperature. The Reducing Gas Generator (aka the Combustor) burns natural gas so the combined combustion products from both units would result in a net increase of emissions. This transition period to the spare unit is expected infrequently (every 2 to 3 years). The emission increase from this proposed project is small.

EMISSIONS CALCULATION

The warmup periods where both Reducing Gas Generators will be operating concurrently will occur no more than 5 times per year. The firing rate during the warmup period will be around 2 MMBtu/hr and last about 12 hours.

The emission factors come from AP-42, Small Boilers, Uncontrolled, Table 1.4-1 and 1.4-2.

NOx: 0.098 lb/MMBtu x 2 MMBtu/hr x 12 hours/event x 5 events/year x ton/2000 lbs = 0.006 ton/year NOx

CO: 0.082 lb/MMBtu x 2 MMBtu/hr x 12 hours/event x 5 events/year x ton/2000 lbs = 0.005 ton/year CO

PM10: 0.0069 lb/MMBtu x 2 MMBtu/hr x 12 hours/event x 5 events/year x ton/2000 lbs = 0.0004 ton/year PM10

SO2: 0.0006 lb/MMBtu x 2 MMBtu/hr x 12 hours/event x 5 events/year x ton/2000 lbs = 0.000036 ton/year SO2

POC: 0.0054 lb/MMBtu x 2 MMBtu/hr x 12 hours/event x 5 events/year x ton/2000 lbs = 0.00032 ton/year VOC

PLANT CUMULATIVE INCREASE

POC: 0.059 (existing)	+	0.00032 (proposed)	= 0.05932 TPY
NOx: 0 (existing)	+	0.006 (proposed)	= 0.006 TPY
SO2: 0 (existing)	+	0.000036 (proposed)	= NEGLIBLE TPY
PM10: 0.004 (existing)	+	0.0004 (proposed)	= 0.0044 TPY
CO: 0 (existing)	+	0.005 (proposed)	= 0.005 TPY

TOXIC RISK SCREEN

The addition of a spare reducing gas generator should not emit toxic compounds in amounts different that previously emitted. Therefore, a toxic risk screen is not required.

PLANT LOCATION

According to the SCHOOL program, the closest school is Semple Elementary, which is just over one mile from the facility.

OFFSETS

The POC offset required is 0.00032 TPY * 1.15 = 0.00036 TPY
The NOx offset required is 0.006 TPY * 1.15 = 0.007 TPY

The plant has elected to use the offset deferral provision allowed in Regulation 2-2-421. The facility has valid Banking Certificates to cover this small increase and the facility's cumulative increase is less than 15 tons/year. As discussed with the applicant, offsets will be provided at least 30 days prior to the date of the annual permit renewal (i.e., no later than July 1, 2004).

The cumulative increase for PM10 is 0.0004 TPY. A review of the available information in the District's databank covering past projects for the Valero Asphalt Plant since April 5, 1991 revealed that there was a pre-existing cumulative increase for PM10 of 0.004 tons/year from Application #7471. Pursuant to the provisions in Regulation 2-2-303, offsets will be deferred until the PM10 cumulative increase exceeds 1.0 ton/year.

COMPLIANCE

The installation of this spare equipment will not change the compliance for the Sulfur Plants S-1 and S-2. Tail gas emissions from S-1 and S-2, abated by either A-24 or A-62, then by A-56, will comply with Regulations 6-301, 6-310 and 6-330:

6-301 **Ringelmann No. 1 Limitation:** Except as provided in Sections 6-303, 6-304 and 6-306, a person shall not emit from any source for a period or periods aggregating more than three minutes in any hour, a visible emission which is as dark or darker than No. 1 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree.

6-310 **Particulate Weight Limitation:** A person shall not emit from any source particulate matter in excess of 343 mg per dscm (0.15 gr. per dscf) of exhaust gas volume.

6-330 **Sulfur Recovery Units:** A person shall not emit from any operation manufacturing sulfur, using as a principal raw material any sulfur-containing material, any emission having a concentration of SO_3 or H_2S0_4, or both, expressed as 100% H_2S0_4, exceeding 183 mg dscm (0.08 gr. dscf) of exhaust gas volume.

The closest school is over a mile from the facility, so the Public Notice requirements of Regulation 2-1-214 do not apply.

Toxics, CEQA, NESHAPS, BACT, Offsets and NSPS do not apply.

CONDITIONS

S-1 and S-2 Sulfur Plants are subject to Conditions #125 and #126. These conditions were modified in the Phase I application (#8028). No new conditions are needed because of adding the new spare tail gas reducing gas generator.

RECOMMENDATION

It is recommended that an Authority to Construct be waived and a Permit to Operate be granted to Valero for Phase II of the proposed project to install the following equipment:

A-62 Spare Tail Gas Reducing Gas Generator, natural gas fired, 9.1 MMBtu/hour

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Douglas W. Hall Date
Supervising Air Quality Engineer