Exhibit 1

1989 Guidance on Limiting Potential to Emit in New Source Permitting

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Washington, D.C. 20460

JUN 13 1989

MEMORANDUM

SUBJECT: Guidance on Limiting Potential to Emit in New Source Permitting

FROM: Terrell E. Hunt
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TO: Addressees

This memorandum transmits the final guidance on conditions in construction permits which can legally limit a source's potential to emit to minor or de minimis levels. We received many helpful comments on the January 24, 1989 draft of this guidance, and have incorporated the comments into the final document wherever possible. A summary of the major changes which have been made to the guidance in response to these comments is provided below.

Several commenters noted that the draft guidance used the term "federally enforceable" to mean both federally enforceable as defined in the new source regulations (40 C.F.R. Sections 52.21(b) (17), 51.165(a) (1) (xiv), 51.166(b) (17)), and enforceable as a practical matter. We have tried to distinguish the places where each term should be used, explained the relationship between the two terms, and indicated that in order to properly restrict potential to emit, limitations must be both federally enforceable as defined in the regulations and practically enforceable.

Some commenters requested that the section on averaging times for production limits be more specific as to when it is appropriate to use limitations which exceed a one month time basis. We have tried to explain why it is not possible to develop generic criteria for making this distinction, and to indicate situations where exceptions to the policy that production and operation limitations not exceed one month may be warranted.

There were some requests for a section on enforcement. We have included a new Section VI which addresses this topic. We also received many good suggestions on the example permit limitations. The section on examples has been substantially reworked to reflect your comments.

Finally, we learned through the comments that in two specific circumstances, short term emission limits are the most useful and reasonable way to restrict and verify limits on potential to emit. These circumstances are: 1) when control equipment is installed but control equipment operating parameters are difficult to measure during enforcement inspections; and 2) in surface coating operations with numerous and unpredictable use of coatings containing varying VOC content, where add-on control equipment is not employed. Therefore, we have made a narrow exception to the flat prohibition on use of emission limits to restrict potential to emit for these specific circumstances, and only when certain additional conditions have been met.

Again, we appreciate the thoughtful comments we have received on this guidance. Please insert this document into your Clean Air Act Compliance/Enforcement Policy Compendium as Item Number H.3. If you have any questions, please contact Judith Katz in the Air Enforcement Division at FTS 382-2843, or Sally Farrell in the Stationary Source Compliance Division at FTS 382-2875.

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DOJ

LIMITING POTENTIAL TO EMIT IN NEW SOURCE PERMITTING

JUNE 13, 1989

AIR ENFORCEMENT DIVISION
OFFICE OF ENFORCEMENT AND COMPLIANCE MONITORING

STATIONARY SOURCE COMPLIANCE DIVISION
OFFICE OF AIR QUALITY PLANNING AND STANDARDS

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Limiting Potential to Emit in New Source Permitting

I. Introduction

Whether a new source or modification is major and subject to new source review under Parts C and D of the Clean Air Act is dependent on whether that source or modification has or will have the potential to emit major or significant amounts of a regulated pollutant. Therefore, the definition of "potential to emit" under the new source regulations is extremely important in determining the applicability of new source review to a particular source. The federal regulations define "potential to emit" as:

> the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of fuel combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

40 C.F.R Sections 52.21(b) (4), 51.165(a) (1) (iii), 51.166(b) (4).

Permit limitations are very significant in determining whether a source is subject to major new source review. This is because they are the easiest and most common way for a source to obtain restrictions on its potential to emit. A permit does not

have to be a major source permit to legally restrict potential emissions. A minor source construction permit issued pursuant to a state program approved by EPA as meeting the requirements of 40 C.F.R. Section 51.160 is federally enforceable. In fact, any permit limitation can legally restrict potential to emit if it meets two criteria: 1) it is federally enforceable as defined by 40 C.F.R. Sections 52.21(b) (17), 51.165(a) (1) (xiv), 51.166(b) (17), i.e., contained in a permit issued pursuant to an EPA-approved permitting program or a permit directly issued by EPA, or has been submitted to EPA as a revision to a State Implementation Plan and approved as such by EPA; and 2) it is enforceable as a practical matter. The second criterion is an implied requirement of the first criterion. A permit requirement may purport to be federally enforceable, but, in reality cannot be federally enforceable if it cannot be enforced as a practical matter.

Non-permit limitations can also legally restrict potential to emit. These limitations include New Source Performance Standards codified at 40 C.F.R. Part 60 and National Emission Standards for Hazardous Air Pollutants codified at 40 C.F.R. Part 61.

The appropriate means of restricting potential to emit through permit conditions has been an issue in recent enforcement cases. Through these cases and through guidance issued by EPA, the Agency has addressed three questions: what types of permit

limitations can legally limit potential to emit; whether long averaging times for production limitations are enforceable as a practical matter; and whether sources may limit potential to emit to minor source levels as a means of circumventing the preconstruction review requirements of major source review.

II. The Louisiana-Pacific Case

In United States v. Louisiana-Pacific Corporation, 682 F. Supp. 1122 (D. Colo. Oct. 30, 1987) and 682 F. Supp. 1141 (D. Colo. March 22, 1988), Judge Alfred Arraj discussed the type of permit restrictions which can be used to limit a source's potential to emit. The Judge concluded that:

> ... not all federally enforceable restrictions are properly considered in the calculation of a source's potential to emit. While restrictions on hours of operation and on the amount of materials combusted or produced are properly included, blanket restrictions on actual emissions are not.

682 F. Supp. at 1133.

The Court held that Louisiana-Pacific's permit conditions which limited carbon monoxide emissions to 78 tons per year and volatile organic compounds to 101.5 tons per year should not be considered in determining "potential to emit" because these blanket emission limits did not reflect the type of permit conditions which restricted operations or production such as limits on hours of operation, fuel consumption, or final product.

The Louisiana-Pacific court was guided in its reasoning by the D.C. Circuit's holding in Alabama Power v. Costle, 636 F. 2d 323 (D.C. Circuit 1979). Before Alabama Power, EPA regulations required potential to emit to be calculated according to a source's maximum uncontrolled emissions. In Alabama Power, the D. C. Circuit remanded those regulations to EPA with instructions that the Agency include the effect of in-place control equipment in defining potential to emit. EPA went beyond the minimum dictates of the D.C. Circuit in promulgating revised regulations in 1980 to include, in addition to control equipment, any federally enforceable physical or operational limitation. The Louisiana-Pacific court found that blanket limits on emissions did not fit within the concept of proper restrictions on potential to emit as set forth by Alabama Power.

Moreover, Judge Arraj found that:

> ...a fundamental distinction can be drawn between the federally enforceable limitations which are expressly included in the definition of potential to emit and (emission) limitations.... Restrictions on hours of operation or on the amount of material which may be combusted or produced ... are, relatively speaking, much easier to "federally enforce." Compliance with such conditions could be easily verified through the testimony of officers, all manner of internal correspondence and accounting, purchasing and production records. In contrast, compliance with blanket restrictions on actual emissions would be virtually impossible to verify or enforce.

Id. Thus, Judge Arraj found that blanket emission limits were not enforceable as a practical matter.

Finally, the Court reasoned that allowing blanket emission limitation to restrict potential to emit would violate the intent of Congress in establishing the Prevention of Significant Deterioration (PSD) program.

III. Types of Limitations that will Restrict Potential to Emit

As an initial matter in this discussion, a few important terms should be defined. Emission limits are restrictions over a given period of time on the amount of a pollutant which may be emitted from a source into the outside air. Production limits are restrictions on the amount of final product which can be manufactured or otherwise produced at a source. Operational limits are all other restrictions on the manner in which a source is run, including hours of operation, amount of raw material consumed, fuel combusted, or conditions which specify that the source must install and maintain add-on controls that operate at a specified emission rate or efficiency. All production and operational limits except for hours of operation are limits on a source's capacity utilization. Potential emissions are defined as the product of a source's emission rate at maximum operating capacity, capacity utilization, and hours of operation.

To appropriately limit potential to emit consistent with the opinion in Louisiana-Pacific, all permits issued pursuant to 40 C.F.R. Sections 51.160, 51.166, 52.21 and 51.165 must contain a

production or operational limitation in addition to the emission limitation in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment. Restrictions on production or operation that will limit potential to emit include limitations on quantities of raw materials consumed, fuel combusted, hours of operation, or conditions which specify that the source must install and maintain controls that reduce emissions to a specified emission rate or to a specified efficiency level. Production and operational limits must be stated as conditions that can be enforced independently of one another. For example, restrictions on fuel which relates to both type and amount of fuel combusted should state each as an independent condition in the permit. This is necessary for purposes of practical enforcement so that, if one of the conditions is found to be difficult to monitor for any reason, the other may still be enforced.

When permits contain production or operational limits, they should also have recordkeeping requirements that allow a permitting agency to verify a source's compliance with its limits. For example, permits with limits on hours of operation or amount of final product should require an operating log to be kept in which the hours of operation and the amount of final product produced are recorded. These logs should be available

for inspection should staff of a permitting agency wish to check a source's compliance with the terms of its permit.

When permits require add-on controls operated at a specified efficiency level, permit writers should include, so that the operating efficiency condition is enforceable as a practical matter, those operating parameters and assumptions which the permitting agency depended upon to determine that the control equipment would have a given efficiency.

An emission limitation alone would limit potential to emit only when it reflects the absolute maximum that the source could emit without controls or other operational restrictions. When a permit contains no limits on capacity utilization or hours of operation, the potential to emit calculation should assume operation at maximum design or achievable capacity (whichever is higher) and continuous operation (8760 hours per year).

The particular circumstances of some individual sources make it difficult to state operating parameters for control equipment limits in a manner that is easily enforceable as a practical matter. Therefore, there are two exceptions to the absolute prohibition on using blanket emission limits to restrict potential to emit. If the permitting agency determines that setting operating parameters for control equipment is infeasible in a particular situation, a federally enforceable permit

containing short term emission limits (e.g. lbs per hour) would be sufficient to limit potential to emit, provided that such limits reflect the operation of the control equipment, and the permit includes requirements to install, maintain, and operate a continuous emission monitoring (CEM) system and to retain CEM data, and specifies that CEM data may be used to determine compliance with the emission limit.

Likewise, for volatile organic compound (VOC) surface coating operations where no add-on control is employed but emissions are restricted through limiting VOC contents and quantities of coatings used, emission limits may be used to restrict potential to emit under the following limited circumstances. If the permitting agency determines for a particular surface coating operation that operating and production parameters (e.g. gallons of coating, quantities produced) are not readily limited due to the wide variety of coatings and products and due to the unpredictable nature of the operation, emission limits coupled with a requirement to calculate daily emissions may be used to restrict potential to emit. The source must be required to keep the records necessary for this calculation, including daily quantities and the VOC content of each coating used. Emission limits may be used in this limited circumstance to restrict potential to emit since, in this case, emission limits are more easily enforceable than operating or production limits.

IV. Time Periods For Limiting Production and Operation

As discussed above, a limitation specifically recognized by the regulations as reducing potential to emit is a limitation on production or operation. However, for these limitations to be enforceable as a practical matter, the time over which they extend should be as short term as possible and should generally not exceed one month. This policy was explained in a March 13, 1987 memorandum from John Seitz to Bruce Miller, Region IV. The requirement for a monthly limit prevents the enforcing agency from having to wait for long periods of time to establish a continuing violation before initiating an enforcement action.

EPA recognizes that in some rare situations, it is not reasonable to hold a source to a one month limit. In these cases, a limit spanning a longer time is appropriate if it is a rolling limit. However, the limit should not exceed an annual limit rolled on a monthly basis. EPA cannot now set out all inclusive categories of sources where a production limit longer than a month will be acceptable because every situation that may arise in the future cannot now be anticipated. However, permits where longer rolling limits are used to restrict production should be issued only to sources with substantial and unpredictable annual variation in production, such as emergency

boilers. Rolling limits could be used as well for sources which shut down or curtail operation during part of a year on a regular seasonal cycle, but the permitting authority should first explore the possibility of imposing a month-by-month limit. For example, if a pulp drier is periodically shut down from December to April, the permit could contain a zero hours of operation limit for each of those months, and then the appropriate hourly operation limit for each of the remaining months. Under no circumstances would a production or operation limit expressed on a calendar year annual basis be considered capable of legally restricting potential to emit.

V. Sham Operational Limits

In the past year, several sources have obtained purportedly federally enforceable permits with operating restrictions limiting their potential to emit to minor or de minimis levels for the purpose of allowing them to commence construction prior to receipt of a major source permit. In such cases where EPA can demonstrate an intent to operate the source at major source levels, EPA considers the minor source construction permit void ab initio and will take appropriate enforcement action to prevent the source from constructing or operating without a major source permit.

The following example illustrates the kind of situation addressed in this section: An existing major stationary source proposes to add a 12.5 megawatt electric utility steam generating unit, and applies for a federally enforceable minor source permit which restricts operation at the unit to 240 hours per year. Because the project is designed as a baseload facility, EPA does not believe that the source intends to operate the facility for only 240 hours a year. Further investigation would probably uncover documentation of the source's intent to operate at higher levels than those for which it is permitted.

This situation raises the question of whether a source can lawfully bypass the preconstruction or premodification review requirements of Prevention of Significant Deterioration (PSD) and nonattainment New Source Review by committing to permit conditions which restrict production to a level at which the source does not intend to operate for any extensive time. If, after constructing and commencing operation, the source obtains a relaxation of its original permit conditions prior to exceeding them, does this constitute a violation of the preconstruction review requirements? This section discusses why it is improper to construct a source with a minor source permit when there is intent to operate as a major source, and provides guidelines for identifying these "sham" permits.

A. Permits with conditions that do not reflect a source's planned mode of operation are void ab initio and cannot act to shield the source from the requirement to undergo preconstruction review.

1. Sham permits are not allowed by 40 CFR Section 52.21(r) (4) Section

52.21(r) (4) states:

> At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980 on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then (PSD) shall apply to the source or modification as though construction had not yet commenced on the source or modification.

When a source that is minor because of operating restrictions in a construction permit later applies for a relaxation of that construction permit which would make the source major, Section 52.21(r) (4) prescribes the methodology for determining best available control technology (BACT). However, it does not foreclose EPA's ability, in addition to the retroactive application of BACT and other requirements of the PSD program, to pursue enforcement where the Agency believes that the initial minor source permit was a sham. EPA will limit its activity to requiring application of 40 CFR 52.21(r) (4) only for the cases where a source legitimately changes a project after finding that the operating restrictions which were taken in good faith cannot be complied with. Whether a source has acted in good faith is a factual question which is answered by available evidence in the particular case.

2. Sham permits are not allowed by the definition of potential to emit:

40 C.F.R. Sections 52.21(b) (4), 51.165(a) (1) (iii), 51.166(b) (4).

The definition of potential to emit enables sources to obtain federally enforceable permits with operational restrictions as a means of limiting emissions to minor source levels. However, implicit in the application of these limitations is the understanding that they comport with the true design and intended operation of the project.

3. Sham permits are not allowed by the Clean Air Act

Parts C and D of the Clean Air Act exhibit Congress's clear intent that new major sources of air pollution be subject to preconstruction review. The purposes for these programs cannot be served without this essential element. Therefore, attempts to expedite construction by securing minor source status through the receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements.

B. Guidelines for determining when minor source construction permits are shams.

EPA's determination that a purportedly federally enforceable construction permit is a sham is made based on an evaluation of specific facts and evidence in each individual case. The following are criteria which should be scrutinized when making such a determination:

1. Filing a PSD or nonattainment NSR permit application

If a major source or major modification permit application is filed simultaneously with or at approximately the same time as the minor source construction permit, this is strong evidence of an intent to circumvent the requirements of preconstruction review. Even a major source application filed after the minor source application, but either before operation has commenced or after less than a year of operation should be looked at closely.

2. Applications for funding

Applications for commercial loans or, for public utilities, bond issues, should be scrutinized to see if the source has guaranteed a c ertain level of operation which is higher than that in its construction permit. If the project would not be funded or if it would not be economically viable if operated on an extended basis

(at least a year) at the permitted level of production, this should be considered as evidence of circumvention.

3. Reports on consumer demand and projected production levels.

Stockholder reports, reports to the Securities and Exchange Commission, utility board reports, or business permit applications should be reviewed for projected operation or production levels. Ifreported levels are necessary to meet projected consumer demand but are higher than permitted levels, this is additional evidence of circumvention.

4. Statements of authorized representatives of the source regarding plans for operation.

Statements by representatives of the source to EPA or to state or local permitting agencies about the source's plans for operation can be evidence to show intent to circumvent preconstruction review requirements.

Note that if a determination is made that a permit is a "sham" for one pollutant and, therefore, the source is a major source or major modification, the permit may possibly still contain valid limits on potential to emit for other pollutants.

In such cases, the entire source must still go through new source review, during which, for PSD review, all pollutants for which there is a net significant increase must be analyzed for BACT. In nonattainment new source review, new sources must have LAER determinations only for pollutants for which they are major. Major modifications, however, must have LAER determinations for all nonattainment pollutants emitted in significant amounts. If the valid limits in a partially void minor source construction permit keep certain pollutants below significance levels, then those pollutants would not have to be analyzed for BACT or LAER. However, if a source or modification is determined to be major for PSD or NSR because part of its minor permit is deemed void, it would have to undergo BACT or LAER analysis for all significant pollutants.

VI. Enforcement Procedures

This guidance has discussed permit conditions which will legally restrict potential to emit, shielding a source from the requirement to comply with major new source permitting regulation. Failure by a permitting agency to adhere to these guidelines may result in a permit that does not legally restrict potential to emit, thereby subjecting a source to major new source review. If that source has not gone through preconstruction review, it is a significant violator of the Clean Air Act and is subject to enforcement for constructing or

modifying without a major new source permit.

The enforcement options available to EPA in these situations include administrative action under Sections 167 or 113 (a) (5) of the Act or federal judicial action under Sections 113 (b) (2), 113 (b) (5), 113(c), or 167. Which enforcement option is selected depends on the facts of the particular situation. (See July 15, 1988 guidance on EPA Procedures for Addressing Deficient New Source Permits.)

VII. Examples

The following examples are provided to illustrate the type of permit restrictions which would and would not legally limit potential to emit to less than major source thresholds. These examples are provided for purposes of clarifying the potential to emit and averaging time guidance only. They are not intended to reflect all the permit conditions necessary for a valid permit. Specific test methods, compliance monitoring and recordkeeping and reporting requirements are necessary to make permit limitations enforceable as a practical matter. The use of examples where averaging times are the longest times allowed under EPA policies is not intended to necessarily condone the selection of the longest averaging times; averaging times should in practice be as short as possible.

1. The minor source construction permit for a boiler contains the following restrictions: 250,000 gal fuel/month; 0.8% S fuel; 8000 hours/year.

These conditions are federally enforceable production and operation limits, but do not limit potential to emit because one of them does not meet EPA policies on enforceability as a practical matter. The averaging time for hours of operation, one of the operational limits necessary to restrict emissions to less than 250 tpy, exceeds a monthly or rolling yearly limit. If, instead of 8000 hours/year, the hourly restriction were stated as 666 hours/month, the permit would serve to keep the source a minor source, assuming the permit contains appropriate recordkeeping provisions.

2. A waferboard plant which has the physical capacity to emit over 300 tpy of carbon monoxide in the absence of using specific combustion techniques has the following permit restriction as the sole emission limitation: 249 tpy.

This does not limit potential to emit since an operational or production restriction is necessary for the source to be restricted to 249 tpy. The permit must contain a restriction on hours of operation or capacity utilization which, when multiplied by the maximum emission rate for the CO sources at the plant, results in emissions of 249 tpy. Additionally, while the

emission limit alone cannot restrict potential to emit, the emission limit is unenforceable as a practical matter since it is limited on an annual basis. The permit should contain a short term emission limit (in addition to the annual emission limit), consistent with the compliance period or parameter in the applicable test method for determining compliance.

3. A small scale rock crushing plant that cannot emit more than 240 tpy under maximum operation without controls (including plant-wide particulate emissions from transfer and storage operations) has the following permit restriction as the sole emission limitation: 240 tpy particulate matter.

Since no operational limitations are necessary for the source to emit below 250 tpy, no operational restrictions need be in the permit to limit potential to emit. However, although this is not a major source, the state agency should express the emission limit in this permit as a lb/hour measure or gr/dscf so that it will be enforceable as a practical matter.

4. A plant consisting solely of a small rock crusher has the following permit restrictions: 0.05 lb gr PM/dscf; fabric filter must be employed and maintained at 99% efficiency.

Assuming that maintaining the fabric filter at 99% efficiency will result in emissions of less than 250 tpy, this permit would limit

potential to emit if it also contained either 1) parameters that allowed the permitting agency to verify the fabric filter's operating efficiency or 2) a requirement to install and operate continuous opacity monitors (COMs) and a specification that COM data may be used to verify compliance with emission limits. Note that if this second alternative were adopted, it would not be necessary to require that the fabric filter be maintained at 99% efficiency.

To determine potential to emit, the efficiency rate of the fabric filter would be multiplied by the maximum uncontrolled emission rate, the maximum number of operating hours and maximum throughput capacity since there are no other operating or production limits. However, the efficiency rate of the fabric filter would not be enforceable as a practical matter unless there were an enforceable means to monitor ESP performance on a short term basis. The two alternatives mentioned above would satisfy this requirement.

5. A surface coating operation has the capability of utilizing 15,000 gal coating/month, with the following permit restrictions: 3.0 lb VOC/gal coating minus water; 20.5 tons VOC/month; monthly VOC emissions to be determined from records of the daily volumes of coatings used times the manufacturers specified VOC content.

This does not limit potential to emit since the source has the physical capacity to exceed 250 tpy of VOC, and the permit does not contain a production or an operational limitation. A monthly limit on gallons of coating used which when multiplied by 3.0 lb/gal equates to less than the 250 tpy threshold 13,500 gallons/month), with appropriate recordkeeping, would generally be necessary to limit potential to emit. If, however, the permitting agency determines, due to the wide variety of coatings employed and products produced, that restrictions on operation or production are not practically enforceable, then the above emission limits could restrict potential to emit if there are requirements that the source calculate emissions daily, and keep the appropriate records.

If the source was alternatively to meet the 20.5 ton/month limit by employing add-on controls, the permit would need to contain an operational limit, such as the requirement to install and operate an incinerator at 99% efficiency. A requirement to monitor incinerator efficiency (either directly or indirectly via temperature monitoring for example), and appropriate recordkeeping retirements to verify compliance with each of the permit conditions would also be necessary to make the permit conditions enforceable as a practical matter. Note, however, that in the case where add-on controls are employed, the source may be able to meet a shorter term emission limit than the ton per month figure.

VIII. Conclusion

We hope this guidance will help EPA Regions identify sources which have the potential to emit major amounts of an air pollutant which will subject those sources to the requirements of preconstruction new source review. Every source which is subject to these requirements but has not obtained a major new source permit should be seriously considered for enforcement action.

Exhibit 2

District Rule 230.1

RULE 230.1 EMISSION REDUCTION CREDIT BANKING
(Adopted September 19,1991, Revised on March 11, 1992)

I. Applicability

The provisions of this rule apply to all transactions involving the storage, transfer, or use of emission reduction credits of affected pollutants.

II. Rule Purposes

A. Provide an administrative mechanism for sources to store emission reduction credits for later use as offsets where allowed by District rules and regulations, or state and federal rules and regulations.

B. Provide an administrative mechanism for sources to transfer emission reduction credits to other sources for use as offsets as allowed by the District's New Source Review rule, or state and federal rules and regulations.

C. Define eligibility standards, quantitative procedures, and administrative practices to ensure that Emission Reduction Credits (ERCs) are real, permanent, quantifiable, surplus, and enforceable.

III. Definitions

A. Unless otherwise defined, terms as used in this rule are defined in the New Source Review Rule.

B. Actual Emission Reductions: as defined in the District's New Source Review Rule. If the reductions are authorized by an Authority to Construct, the adjustments made to the actual emissions reductions as defined in the New and Modified Stationary Source Review Rule, shall be based on the rules, plans, workshop notices at the time the application for such Authority to Construct was deemed complete.

C. Bankable Emission Reductions: emission reductions of pollutants and their precursors for which ambient air quality standards exist, and which meet the provisions of this Rule. Such reductions may be deposited in the District's ERC Bank. Once banked and certified, the emission reductions become Emission Reduction Credits (ERCs).

D. Banking: the District's system of quantifying, certifying, recording, and storing ERCs for future use or transfer. This system shall be called the District's Emission Reduction Credit Bank (herein referred to as the ERC Bank").

E. Banking Register: the document that records all ERC deposits, withdrawals, transfers, and transactions.

F. Baseline Period: the same period as defined in the District's New Source Review Rule.

G. Emission Reduction Credits (ERCs): reductions of actual emissions emission unit recognized by the District as available for use as tradeoffs or offsets in accordance with the requirements of this Rule. To be eligible for certification as ERCs, emissions reductions must be real, surplus, permanent, quantifiable and enforceable. All emission reduction meeting these requirements may be certified as ERCs.

H. ERC Certificate: a document certifying title to a defined quantity and type of ERCs issued by the District to the owner(s) identified on the Certificate.

I. Non-inventoried Emissions: those emissions of an air pollutant into the atmosphere from any source which has not been recorded on the District emission inventory.

J. Non-permitted Emissions: those emissions of an air pollutant into the atmosphere open air from non-permitted emission sources that are not required to have air pollution permits. Non-permitted emissions may include emissions from agricultural waste burning, mobile source emissions, exempt emission unit, and sources that were never subject to the requirements of the District's New Source Review Rule.

K. Offset: the use of an ERC to mitigate emission increases of an affected pollutant from a new or modified source subject to the requirements of District's new Source Review Rule.

L. Shutdown: shall mean either the earlier of the permanent cessation of emissions from an emitting unit or the surrender of that unit's operating permit. If, prior to the surrender of the operating permit, the Control Officer determines that: a) the unit has been removed or fallen into an inoperable and unmaintained condition such that start-up would require an investment exceeding 50% of the current replacement cost; and b) the owner cannot demonstrate to the

satisfaction of the Control Officer that the owner intended to operate again, then the Control Officer may cancel the permit and deem the source shutdown as of the date of last emissions. Evidence of "intent to operate again" may include valid production contracts, orders, other agreements, or any economically based reasons which would require the operation of the emitting unit after initial cessation of emissions.

M. Transfer: the conveyance of an ERC from one entity to another.

IV. Eligibility of Emission Reductions

A. Emissions reductions before September 19, 1991

For the purposes of this Subsection Distict means the San Joaquin Unified Air Pollution Cotrol District (SJVUAPCD) or any former county Air Pollution Control District that is now included in the SJVUAPCD.

Upon application and approval by the Control Officer the following emissions reductions occurring prior to September 19, 1991, may receive Emissions Reduction Banking Certificates.

1. Emission reduction occurring after January 1, 1988 and prior to the date of adoption of this rule which have been recognized by the District prior to (the adoption date of) this rule, pursuant to a banking rule or pursuant to a formal internal tracking mechanism shall be deemed eligible emission reductions, provided:

   a. The Control Officer determines that such emission reductions comply with the definition of Actual Emission Reduction;

   b. The reductions are real, surplus, permanent, quantifiable, and enforceable;and

   c. The have not been used for approval of an Authority to Construct or used as offsets.

2. Emissions reductions occurring prior to January 1, 1988 which have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets shall be eligible for emissions reductions banking certificates provided:

a. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable;

b. The reductions have not been used for the approval of an Authority to Construct or used as offsets; and

c. The reductions are included in or have been added to the 1987 emissions inventory.

d. A banking application is filed within 180 days of (date of rule adoption) in accordance with the requirements of Section VI, and the applicable requirements of Section VIII are met.

3. Under no circumstances shall any emissions reductions occurring before September 19, 1991, other than as described in Subsection IV.A.1. or IV.A.2. be eligible for emissions reduction credit banking certificates.

B. Emissions Reductions Occurring After September 19, 1991

For emission reductions occurring after September 19,1991, the following criteria must be met in order to deem such reductions eligible for banking:

1. The emission reduction are real, surplus, permanent, quantifiable, and enforceable.

2. Actual emission reductions are calculated in accordance with the calculation procedures of the District's New Source Review Rule and comply with the definition of Actual Emission Reductions of the District's New Source Review Rule. Adjustment to emissions reductions for the community bank shall be made at the time the reductions a quantified pursuant to the District's New Source Review Rule.

3. An application for ERC has been filed no later than 180 days after the emission reductions occurred.

4. For non-permitted emission units emissions must have been included in the 1987 emissions inventory and the source creating ERCs shall apply for and acquire a Permit to Operate subject to enforceable

permit conditions which ensures that the emission reductions will be provided in accordance with the provisions of this rule, and shall continue for the reasonably expected life of the proposed stationary source. If the district, pursuant to state laws, is prohibited to permit the emission unit, the stationary source creating ERC's shall execute a legal binding contract with the District which ensures that the emission reductions will be provided in accordance with the provisions of this rule, and shall continue for the reasonably expected life of the proposed source.

C. A stationary source which provided offsets for increase in permitted emissions prusuant to New and Modified Stationary Source Review and has been issued an Authority to Construct since January 1, 1988 may apply to bank such offsets pursuant to Subsection IV.B. if the Authority to Construct is voluntarily surrendered, expires or is cancelled or if the Permit to Operate resulting from such Authroity to Construct is voluntarily modified, surrendered or is revoked.

D. The following emission reductions are not eligible as Emission Reduction Credits for banking:

1. Emission reductions from the shutdown or curtailment of gasoline dispensing facilities, dry cleaning facilities.

2. Emission reductions occurring at a fossil fuel fired power plant as the result of the operation of a cogeneration facility.

3. Emission reductions occurring from the shut down or curtailment of a stationary source for which the District originally provided the required offsets.

4. Emission reductions occurring from the shutdown or curtailment of a stationary source for which the offsets originally provided are no longer enforceable by the District such as reductions in open burning of agricultural waste used to offset emissions from a resource recovery project.

V. ERC Certificate Application Procedures

A. Any entity which owns or operates a source at which an eligible emission reduction has occurred or will occur may apply for an ERC Certificate in accordance with the requirements of this Rule.

B. The entity requesting the ERC Certificate shall make an application on forms supplied by the District.

C. An application shall be filed for each emission reduction. The application may be for reductions in one or more affected pollutant. The application shall contain sufficient information to allow for adequate evaluation of actual emission reductions from each emission unit.

D. In accordance with the provisions of Rule 103 and Section 114(c) of the Federal Clean Air Act, applicants may claim confidentiality of information contained in the application.

E. Except for reductions covered under subsection IV.A., ERC Certificate applications for reductions shall be submitted within 180 days after the emission reduction occurs. For reductions covered under Subsection IV.A., ERC Certificate applications shall be submitted within 180 days of the adoption date of this rule.

F. Where appropriate, to confirm emission reductions claimed in conjunction with an application for an ERC Certificate, the District may require source tests, continuous monitoring, production records, fuel use records, or any other appropriate means of measurement.

H. The form of the ERC Certificate shall be established by the Control Officer.

I. ERC applicants for emission reductions derived from a single reduction at a single emitting unit may apply for and receive single or multiple ERC Certificates. Multiple ERC Certificates shall be issued for each owners' proportional share.

VI. Registration of ERC Certificates

A. The Control Officer may only grant an ERC Certificate after the emission reductions have actually occurred upon satisfaction of the following applicable provision(s):

1. A revised Permit to Operate has been issued if the emission reductions were created as a result of

greater operating efficiencies or from the application of more efficient control technology. This revised permit must include specific quantifiable emission limits reflecting the reduced emissions;

2. If the emission reductions were created as a result of the shutdown of a permitted emissions unit, the relevant Permit(s) to Operate has been surrendered and voided.

3. If the emission reductions from a permitted emissions unit were created by means of reducing production or production rates, the relevant Permit to Operate have been modified to reflect the emission reductions.

4. If the emission reductions were created as a result of the application of greater operating efficiencies or from the application of a more efficient control technology to a then non-permitted source: a) Permit(s) to Operate has been obtained, or b) written contract between the owner or operator of such source and the ERC applicant has been executed, which by its terms, shall be enforceable by the Control Officer. The referenced permit or contract shall include specific quantifiable emission limits reflecting reduced emissions. If the emissions reductions were created as a result of the modification of a non-permitted emissions unit, the stationary source shall be prohibited from operating a new emissions unit in the same source category without first obtaining Authority to Construct and Permit to Operate.

B. Where appropriate, to confirm emission reductions claimed in conjunction with an application for an ERC Certificate, the Control Officer may require source tests, continuous monitoring, production records, fuel use records, or any other appropriate means of measurement.

C. The form of the ERC Certificate shall be established by the Control Officer.

D. ERC applicants for emission reductions derived from a single reduction at a single emitting unit may apply for and receive single or multiple ERC Certificates. Multiple ERC Certificates shall be issued for each owners' proportional share.

E. When all the requirements of this Rule have been satisfied and the emission reduction has actually occurred, the Control Officer shall issue the ERC Certificate. Upon the Control Officer's determination to grant an ERC Certificate, title to such ERC shall be registered in the Banking Register. Such titles may be computerized and made available for public inspection.

F. All information concerning titles, interests, and other matters such as liens, encumbrances, and changes of record shall be identified in the District's ERC Banking Register, as well as pertinent date(s) concerning such information, until such time as the ERC Certificate is public information, until such time as the ERC Certificate is used, cancelled, or nullified by operation of law.

G. Each ERC Certificate shall be numbered, bear the date of issuance, be signed by the District official charged with the responsibility of keeping the District's ERC Bank, and bear the seal of the District. One copy of the ERC Certificate shall be retained by the District and the original shall be delivered to the owner or party acting for the owner. The record of issued ERC Certificates shall be retained by the District, and this record may be in computer storage. Delivery by the District of an ERC Certificate to an owner shall be accomplished in person or by registered mail. The person accepting the ERC Certificate must sign a receipt therefore and provide such proof of identity as the Control Officer shall require.

H. At the option of joint owners of ERCs, such persons may receive one ERC Certificate for the entirety or separate ERC Certificates reflecting each proportional share, provided that such ERCs are derived from a single reduction at a single emitting unit. The District's ERC Bank shall reflect the consolidation or separation of the ERCs and the previous Certificate(s) shall be cancelled upon the issuance of the new Certificate(s).

I. After receiving written notice from an owner that they have released their right of control of valid existing banked emission reductions, or if an owner fails to file an application for banking emission reductions in accordance with procedures outlined in this rule, the control officer may place such emission reductions in the District's Community Bank without consent from the owner.

J. Adjustments to the quantity of banked ERCs shall be

allowed without the owner's consent so long as the action to reduce the quantity of ERCs is consistent with applicable District, State, and Federal rules and/or planning requirements, including Reasonable Further Progress Actions to reduce the quantity of banked ERCs which are inconsistent with applicable District, State, or Federal rules shall require the consent of the owner. Such adjustments shall only be made after public notice and hearing.

K. Prior to adjusting the estimated quantity or the conditions of deposit, use, or withdrawal of banked ERCs for any reason, the Control Officer shall notify the ERC Certificate owner in writing.

L. Except as provided in Subsection VI.J. of this Rule, deposits are permanent until used by the depositor or any party to whom the ERC Certificate has been transferred. After issuance of the ERC Banking Certificate, subsequent changes in regulations to require the type of reduction banked shall not reduce or eliminate the deposit.

M. If the Control Officer determines that additional mandatory emission reductions will be necessary to achieve ambient air quality standard(s), the Control Officer may declare a full or partial moratorium on banked ERCs of the applicable contaminant. Prior to imposing any kind of moratorium, the Control Officer must provide public notice that the District has determined that sufficient emission reductions cannot be achieved through the imposition of controls on existing permitted or non-permitted emitting emissions units. Should such a determination be made, a moratorium on deposits shall first be imposed. Should the Control Officer determine that a moratorium on withdrawals of banked ERCs is also necessary to attain applicable air quality standards, a public notice shall first be provided to this effect. Only after a public hearing resulting in the determination that a moratorium is needed and written notice to ERC Certificate owners of the applicable contaminant may any moratorium be imposed. Any such moratorium shall be lifted upon the determination by the Control Officer and public notice that Reasonable Further Progress can be demonstrated by the District.

N. Title to an ERC shall be deemed registered at the time the required information concerning the ERC are entered into the Register.

O. All dealings with ERCs or any interest therein, and all

liens, encumbrances, and charges upon the same subsequent to the first registration thereof, shall be deemed to be subject to the terms of this regulation, and to such amendments and alterations as may hereafter be made.

P. The Control Officer may reissue lost or destroyed ERC Certificates after the owner vouches that the original has been lost or destroyed.

VII. Withdrawal, Transfer, and Use of ERCs

A. ERCs may be used at the time of, or anytime after deposit into the District's ERC Bank by the owner of the ERC Certificate to provide contemporaneous offsets for increase in onsite emissions from new or modified emission units.

B. An ERC Certificate may be transferred or used in whole or in part and in accordance with provisions of this rule.

Transfer in whole or in part of a registered ERC Certificate shall be done in accordance with application procedures of this rule. Upon payment of application fee a new ERC Certificate, certifying the title or interest in the ERC, shall be issued and the last previous original(s) shall be cancelled. Such cancellation shall be recorded in the Banking Register.

C. Nothing in this rule prevents the lease or temporary transfer, in whole or in part of, ERCs represented by ERC Certificates. However, all transfers shall be considered permanent until modified by application which demonstrates to the satisfaction of the Control Officer that the emissions for which the ERCs were required have either ceased or other emission reductions have been secured.

D. All emissions reductions to be used as offsets which are not contemporaneous with emissions increases shall be transferred by application pursuant to this Rule. Reductions to be used as offsets which are contemporaneous and meet the requirements of the New and Modified Stationary Source Review Rule and the Requirements of this Rule may take place without application for ERC.

VIII. Fees and Administrative Requirements

A. A fee of $650 shall accompany each ERC Certificate application. The District, upon notification to the applicant, may assess reasonable additional fees should the Control Officer determine that the fee will not cover the time and effort needed to assess the merits of the application.

Upon notification that an additional fee shall be required, the applicant may withdraw an application without incurring such additional fee.

B. The Control Officer shall determine whether an ERC Banking Certificate application is complete not later than thirty (30) calendar days following receipt of the application, or after a longer time period agreed upon in writing by both the applicant and the Control Officer.

C. If the Control Officer determines that the application is not complete, the applicant shall be notified in writing of the decision, specifying the additional information that is required. The applicant shall have ninety (90) days to submit the requested information. Upon receipt of all requested information, the District shall have thirty (30) days to determine completeness. If no data is submitted or the application is still incomplete, the Control Officer may cancel the ERC Banking Certificate application with written notification to applicant. Upon determination that the application is complete, the Control Officer shall notify the applicant in writing. Thereafter, only information to clarify, correct, or otherwise supplement the information submitted in the application may be requested.

D. Withdrawal of a banking application by an applicant shall result in cancellation of the application; any re-submittal shall be evaluated using a baseline calculated as of the date of re-submittal.

E. Upon acceptance of a complete application, the Control Officer shall have sixty (60) days to perform an initial assessment of the application. Upon completion of this initial assessment the District shall provide written notice of such to the applicant and shall also provide written notice of acceptance to ARB, EPA and publish notice in a newspaper of local and general circulation in the District. The notice shall specify the applicant and the quantity of emission reductions requested and a statement of the initial assessment.

Publication of the notice shall commence a thirty (30)

day public comment period during which the Control Officer shall accept written comments on the merits of the ERC Certificate application. Upon conclusion of this thirty (30) day period, the Control Officer shall have thirty (30) days to render a decision as to whether the Control Officer approves, conditionally approves, or denies the application. This decision shall be promptly supplied in writing to the applicant and published in a newspaper of local circulation.

The noticing requirements period shall be waived by the Control Officer if the emission reductions have already been subject to ARB, EPA and public comment. Noticing requirements shall not be waived for emissions reduction which were not formally banked and which occurred prior to January 1, 1988.

F. The applicant or any other party may appeal the Control Officer's decision following provisions specified in the District's Regulation V.

G. The District shall Maintain a Bank Register, which shall consist of a record of all deposit applications, deposits, withdrawals, and transactions with regard to the District's ERC Bank.

Exhibit 3

District Rule 2201

RULE 2201 NEW AND MODIFIED STATIONARY SOURCE REVIEW RULE (Adopted September 19, 1991; Amended March 11, 1992; Amended October 29, 1992; Amended December 17, 1992; Amended October 21, 1993; Amended June 15, 1995; Amended August 20, 1998; Amended June 21, 2001, but not effective until August 20, 2001; Amended April 25, 2002; Amended December 19, 2002; Amended April 20, 2005; Amended December 15, 2005; Amended September 21, 2006; Amended December 18, 2008, but not in effect until June 10, 2010; Amended April 21, 2011; Amended February 18, 2016; Amended August 15, 2019; Amended April 20, 2023, but not in effect until August 9, 2023)

1.0 Purpose

The purpose of this rule is to provide for the following:

1.1 The review of new and modified Stationary Sources of air pollution and to provide mechanisms including emission trade-offs by which Authorities to Construct such sources may be granted, without interfering with the attainment or maintenance of Ambient Air Quality Standards; and

1.2 No net increase in emissions above specified thresholds from new and modified Stationary Sources of all nonattainment pollutants and their precursors.

2.0 Applicability

This rule shall apply to all new stationary sources and all modifications to existing stationary sources which are subject to the District permit requirements in Regulation II and after construction emit or may emit one or more affected pollutant. The requirements of this rule in effect on the date the application is determined to be complete by the Air Pollution Control Officer (APCO) shall apply to such application.

3.0 Definitions

The following definitions apply for all terms used in this Rule. If a term is not defined herein, then the definitions provided in Rule 1020, Definitions, shall apply.

3.1 Actual Emissions: emissions having occurred from a source, based on source test or monitoring data, actual fuel consumption, and process data. If source test or monitoring data is not available, other appropriate, APCO-approved, emission factors may be used. For Federal Offset Quantity calculations, the emissions shall be from a consecutive 24-month period, representative of normal source operation, and for any emissions unit that has not begun normal operations, actual emissions shall equal the pre-project potential to emit of the emissions unit.

3.2 Actual Emissions Reduction (AER): the quantity of emission reductions from an emissions unit, measured as the difference between the post-project potential to emit and the pre-project Actual Emissions that were emitted during the Baseline Period. An AER selected for use as an emission offset or ERC banking shall also be real, enforceable, quantifiable, surplus, and permanent.

3.2.1 Surplus: an AER that is in excess, at the time the application for an Emission Reduction Credit or an Authority to Construct authorizing such reductions is deemed complete, of any emissions reduction which:

3.2.1.1 Is required or encumbered by any laws, rules, regulations, agreements, orders, or

3.2.1.2 Is attributed to a control measure noticed for workshop, or proposed or contained in a State Implementation Plan, or

3.2.1.3 Is proposed in the APCO's adopted air quality plan pursuant to the California Clean Air Act.

3.2.2 Emissions reductions attributed to a proposed control measure, which are excluded pursuant to Section 3.2.1.2 and 3.2.1.3 may be re-eligible as an AER if the control measures identified in the District Air Quality Plan or State Implementation Plan (SIP), are determined not to be necessary for attainment or maintenance of Ambient Air Quality Standards and the APCO and United States Environmental Protection Agency (EPA) have approved amendments to the plan or SIP to reflect this determination.

3.3 Administrative Change: a change to an existing permit that:

3.3.1 Corrects typographical errors; or

3.3.2 Corrects or updates the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source; or

3.3.3 Corrects or updates the components of emissions monitoring equipment or other components, which have no effect on the quantity of emissions from an emissions unit; or

3.3.4 Allows for the change of ownership or operational control of a source where the APCO determines that no other change to the permit is necessary.

3.4 Affected Pollutants: those pollutants for which an Ambient Air Quality Standard has been established by the EPA or by the California Air Resources Board, (ARB), and the precursors to such pollutants, and those pollutants regulated by the EPA under the Federal Clean Air Act or by the ARB under the Health and Safety Code including, but not limited to, VOC, NO_x, SO_x, PM2.5, PM10, CO, and those pollutants which the EPA, after due process, or the ARB or the APCO, after public hearing, determine may have a significant adverse effect on the environment, the public health, or the public welfare.

3.5 Agricultural Source: equipment or operations that emit air contaminants and that are used in the production of crops or the raising of fowl or animals.

3.6 Air Quality Improvement Deduction: a 10 percent discount factor applied to Actual Emission Reductions (AER) before the AER is banked.

3.7 Ambient Air Quality Standards: include State and National Ambient Air Quality Standards. (In the inclusion of this rule in the State Implementation Plan, all references in this rule to Ambient Air Quality Standards shall be interpreted as National Ambient Air Quality Standards.)

3.8 Baseline Emissions (BE): for a given pollutant, shall be equal to the sum of:

3.8.1 The pre-project Potential to Emit for:

3.8.1.1 Any emissions unit located at a non-Major Source,

3.8.1.2 Any Highly-Utilized Emissions Unit, located at a Major Source. If the emissions unit is subject to a Specific Limiting Condition (SLC), then for a given pollutant, all emissions units combined under the SLC must have average combined annual Actual Emissions during the 24 consecutive months immediately prior to filing an application for an Authority to Construct equal to or greater than 80% of the emissions units' pre-project SLC limit,

3.8.1.3 Any Fully-Offset Emissions Unit, located at a Major Source. If the emissions unit is subject to a SLC, then all emissions units under the SLC must also qualify as Fully Offset Emissions Units, or

3.8.1.4 Any Clean Emissions Unit, located at a Major Source, provided that if the unit has a SLC, all units under the SLC also qualify as Clean Emissions Units.

3.8.2 The Historical Actual Emissions (HAE) for emissions units not specified in Section 3.8.1.

3.9 Baseline Period: a period of time equal to:

3.9.1 The 24 consecutive months of operation immediately prior to the submission date of the Complete Application; or

3.9.2 At least 24 consecutive months within the five years immediately prior to the submission date of the Complete Application if determined by the APCO as more representative of normal source operation; or

3.9.3 Except for federal emission offset requirements pursuant to Section 4.8, a shorter period of at least 12 months if the emissions unit has not been in operation for 24 months and this represents the full operational history of the emissions unit, including any replacement units; or

3.9.4 Zero years if an emissions unit has been in operation for less than one year (only for use when calculating AER).

3.10 Best Available Control Technology (BACT): is the most stringent emission limitation or control technique of the following:

3.10.1 Achieved in practice for such class or category of source;

3.10.2 Contained in any State Implementation Plan approved by the Environmental Protection Agency for such class or category of source. A specific limitation or control technique shall not apply if the owner of the proposed emissions unit demonstrates to the satisfaction of the APCO that such a limitation or control technique is not presently achievable; or

3.10.3 Contained in an applicable federal New Source Performance Standard; or

3.10.4 Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be cost effective and technologically feasible for such class or category of sources or for a specific source.

3.11 Best Available Retrofit Control Technology (BARCT) Rule: a District rule which includes an air emission limit that applies to existing sources and is the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts by each class or category of source.

3.12 Biomass-fired power facility: a facility generating electrical power and fueled exclusively on biomass fuels consisting of at least 90% of one or more of the following constituents: alfalfa, barley, bean straw, corn, oats, wheat, orchard and vineyard pruning, and forest residues. Grape stems, grape pumice, almond and walnut shells, construction wood waste, urban wood waste, and lawn trimmings are not considered biomass fuels.

3.13 Cargo Carriers: trains dedicated to a specific Stationary Source and vessel dockside activities as defined in 45 Federal Register 52696 (August 7, 1980) for vessels dedicated to a specific Stationary Source. Motor vehicles, as defined by the Vehicle Code of the State of California, are not considered Cargo Carriers.

3.14 Clean Emissions Unit: for a given pollutant, an emissions unit that meets one of the following criteria:

3.14.1 The unit is equipped with an emissions control technology with a minimum control efficiency of at least 95% (or at least 85% for lean-burn, internal combustion engines); or

3.14.2 The unit is equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

3.15 Complete Application: an application for an Emission Reduction Credit or an Authority to Construct for a new or modified emissions unit(s) which has been evaluated and found to include all information necessary to determine compliance with applicable rules and requirements, including, but not limited to the following information:

3.15.1 The nature and amount of emissions to be emitted or reduced, and

3.15.2 The location, design, construction, and operation of such emissions unit(s).

3.16 Contiguous or Adjacent Property: a property consisting of two or more parcels of land with a common point or boundary, or separated solely by a public roadway or other public right-of-way.

3.17 Daily Emissions Limitation (DEL): one or more permit conditions which restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. A daily emissions limitation must be:

3.17.1 Contained in the latest Authority to Construct and contained in or enforceable by the latest Permit to Operate for the emissions unit; and

3.17.2 Enforceable, in a practical manner, on a daily basis.

3.18 Emissions Unit: an identifiable operation or piece of process equipment such as a source operation which emits, may emit, or results in the emissions of any affected pollutant directly or as fugitive emissions.

3.19 Federal Baseline Emissions (FBE): for a given pollutant, shall be equal to the sum of:

3.19.1 The pre-project Potential to Emit for:

3.19.1.1 Any Highly-Utilized Emissions Unit, or

3.19.1.2 Any Fully-Offset Emissions Unit.

3.19.2 The Historical Actual Emissions (HAE) for emissions units not specified in Section 3.19.1.

3.20 Federal Offset Quantity (FOQ): The quantity of offsets or AERs required to satisfy federal emission offset requirements contained in Section 4.8.

3.21 Federal Major Modification: same as “Major Modification” as defined in 40 CFR 51.165. For the purposes of this definition, all terms used in this definition are as

defined in 40 CFR 51.165. Federal Major Modification applicability shall be determined using the following procedures:

3.21.1 Except for VOC and NOx, an emissions increase for the project, or a net emissions increase for the project shall be determined pursuant to 40 CFR 51.165 (a)(2)(ii)(B) through (D), (F), and (G).

3.21.2 For VOC and NOx, an emissions increase for the project shall be determined pursuant to 40 CFR 51.165 (a)(2)(ii)(B) through (D), and (F). The "sum of the difference" as used in 40 CFR 51.165 (a)(2)(ii)(C), (D), and (F) shall not include decreases in emissions.

3.21.3 To determine the post-project projected actual emissions from existing units, the provisions of 40 CFR 51.165 (a)(1)(xxviii) shall be used.

3.21.4 To determine the pre-project baseline actual emissions, the provisions of 40 CFR 51.165 (a)(1)(xxxv)(A) through (D) shall be used.

3.21.5 Except for projects at a stationary source with a Plantwide Applicability Limit, if the project is determined not to be a federal major modification, but there is a reasonable possibility as described in 40 CFR 51.165 (a)(6)(vi) that the project may result in a significant emissions increase, the owner or operator shall comply with all of the provisions of 40 CFR 51.165 (a)(6) and (a)(7).

3.21.6 Emissions increases calculated pursuant to this section are significant if they exceed the significance thresholds specified in Table 3-1 of this rule.

Table 3-1, Significance Thresholds

POLLUTANT	THRESHOLD (POUNDS PER YEAR)
VOC	0
NOx	0
PM2.5	20,000 of direct PM2.5 emissions or
	80,000 of sulfur dioxide emissions or
	80,000 of nitrogen oxide emissions
PM10	30,000
SOx	80,000

3.21.7 Plantwide Applicability Limit (PAL) Exclusion: An SB 288 major modification that does not cause facility-wide emissions to exceed a pre-established PAL, as defined in 40 CFR 51.165 (f)(2)(v), for the respective pollutant, is not a federal major modification for that pollutant. PAL exclusions shall not be allowed for either NOx or VOC pollutants.

3.21.7.1 For the purposes of this exclusion, a PAL must be established by a permitting action prior to the SB 288 major modification permitting action.

3.21.7.2 All PALs shall be established according to the provisions of 40 CFR 51.165 (f)(1) through (15).

3.21.7.3 All PALs shall comply with the requirements under 40 CFR 51.165 (f)(1) through (15) to either maintain, renew or retire the PAL.

3.22 Fugitive Emissions: emissions that could not reasonably pass through a vent, chimney, stack, or other functionally equivalent opening. Emissions that are not vented through a stack but can reasonably be captured and vented through a stack are not considered Fugitive. Fugitive emissions shall be included in all calculations, except as provided for in Section 3.28 and as allowed in the applicable 40 CFR Part 51.165.

3.23 Fully Offset Emissions Unit:

3.23.1 For Federal Offset Quantity calculations, determined on a pollutant-by-pollutant basis:

3.23.1.1 An emissions unit for which offsets were provided for the unit's full potential to emit, and

3.23.1.2 The offsets were provided within the 5-year period prior to the submission date of the Complete Application and shall have been surplus at time-of-use.

3.23.2 For District Offset Quantity calculations, determined on a pollutant-by-pollutant basis, an emissions unit for which:

3.23.2.1 Offsets have been provided for the unit's full potential to emit; or

3.23.2.2 Offsets have been provided for the entire stationary source's potential to emit in excess of the offset trigger level; or

3.23.2.3 Offsets have previously been provided for the stationary source's New Source Review (NSR) balance as calculated pursuant to the NSR rule in effect at the time of the offset action, and the emissions unit was installed after the County baseline date as indicated below:

Table 3-2, County Baseline Dates

COUNTY	BASELINE DATE
San Joaquin County	May 29, 1979
Stanislaus County	June 19, 1979
Merced, Madera, or Kings County	May 21, 1979
Fresno County Oil Fields	September 20, 1983
Fresno County all other sources	January 1, 1977
Tulare County	June 26, 1979
Kern County Heavy Oil Production	September 12, 1979
	June 22, 1987 for heavy oil production operations with negative cumulative net emissions change as of June 22, 1987
Kern County all other sources	December 28, 1976

3.24 Heavy Oil: crude oil having an American Petroleum Institute gravity of 20 degrees or less as determined by test method ASTM 287-82.

3.25 Highly-Utilized Emissions Unit: for a given pollutant, an emissions unit for which the average annual Actual Emissions during the 24 consecutive months immediately prior to filing of an application for an Authority to Construct were equal to or greater than 80% of the unit's pre-project Potential to Emit. The unit must have been in operation for at least 24 months and, during that entire period, the unit must have complied with all applicable emission limits and performance standards.

3.26 Historical Actual Emissions (HAE): Actual Emissions occurring during the Baseline Period, after discounting for:

3.26.1 Any emissions reductions required or encumbered by any laws, rules, regulations, agreements, orders, or permits; and

3.26.2 Any emissions reductions attributed to a control measure noticed for workshop, or proposed or contained in a State Implementation Plan, and

3.26.3 Any emissions reductions proposed in the District air quality plan for attaining the annual reductions required by the California Clean Air Act, and

3.26.4 Any Actual Emissions in excess of those required or encumbered by any laws, rules, regulations, orders, or permits. For units covered by a Specific Limiting Condition (SLC), the total overall HAE for all units covered by SLC must be discounted for any emissions in excess of that allowed by the SLC.

3.27 Internal Emission Reductions (IER): Actual Emission Reductions which have occurred or will occur, consistent with the requirements in Sections 4.8.1.5, 4.8.1.6,

4.8.1.7, and 4.8.3, at the same major source where the proposed emissions increase will occur.

3.28 Major Source: for each pollutant, a Stationary Source with post-project emissions or a post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

3.28.1 For determining major source status, fugitives shall only be included for calculating the air pollutant post-project emissions or SSPE2 if the source is included in the source categories listed in 40 CFR 51.165(a)(1)(iv)(C), or when determining if a stationary source is a major air toxics source as defined in Rule 2520.

Table 3-3, Major Source Emission Thresholds

POLLUTANT	THRESHOLD (POUNDS PER YEAR)
VOC	20,000
NOx	20,000
CO	200,000
PM2.5	140,000
PM10	140,000
SOx	140,000

3.28.2 For the purpose of determining major source status, the SSPE2 shall not include the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. This ERC quantity includes all ERC held as certificates and all emission reduction credits that have been sold or transferred.

3.28.3 For the purpose of determining major source status, the SSPE2 shall not include the quantity of emissions resulting directly from a nonroad engine as defined in Section 216 of Part A of the CAA.

3.29 Modification:

3.29.1 An action including at least one of the following items:

3.29.1.1 Any change in hours of operation, production rate, or method of operation of an existing emissions unit, which would necessitate a change in permit conditions.

3.29.1.2 Any structural change or addition to an existing emissions unit which would necessitate a change in permit conditions. A Routine Replacement Emissions Unit shall not be considered to be a structural change.

3.29.1.3 An increase in emissions from an emissions unit caused by a modification of the Stationary Source when the emissions unit is not subject to a daily emissions limitation.

3.29.1.4 Addition of any new emissions unit which is subject to District permitting requirements.

3.29.1.5 A change in a permit term or condition proposed by an applicant to obtain an exemption from an applicable requirement to which the source would otherwise be subject.

3.29.1.6 A Federal Major Modification.

3.29.2 A reconstructed Stationary Source shall be treated as a new Stationary Source and not as a modification.

3.29.3 Unless previously limited by a permit condition, the following shall not be considered a modification:

3.29.3.1 A change in ownership of an existing emissions unit with valid Permit to Operate provided that the APCO determines that all applicable offset provisions required by the Permit to Operate will be met;

3.29.3.2 A change in ownership of an entire existing Stationary Source with a valid Permit to Operate;

3.29.3.3 A change which consists solely of a transfer of location of an emissions unit within a Stationary Source; or

3.29.3.4 A Routine Replacement Emissions Unit where the replacement part is the same as the original emissions unit in all respects except for the serial number.

3.30 New Major Source: A project with an emissions increase equal to or exceeding the major source emission threshold on a pollutant-by-pollutant basis, calculated pursuant to Section 4.8.4.3. When determining the emissions increase, fugitive emissions shall only be included for a source category listed in 40 CFR 51.165(a)(1)(iv)(C). Emissions that originate directly from a nonroad engine shall not be included.

3.31 Offsets: emission reductions recognized by the APCO in the form of Emission Reduction Credits that are issued in accordance with the provisions of Rule 2301 (Emission Reduction Credit Banking), or other Actual Emissions Reductions that may be used to mitigate an emission increase as part of the same Stationary Source Project in accordance with the provisions of this rule.

3.32 Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including pollution control equipment and restrictions in hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is incorporated into the applicable permit as an enforceable permit condition. Secondary source emissions do not count in determining the potential to emit of a stationary source.

3.33 Pre-baseline ERCs: Emission Reduction Credits that were banked prior to the baseline year for a given District-adopted and EPA-approved Attainment Plan.

3.34 Precursor: a directly emitted air contaminant that, when released into the atmosphere, forms or causes to be formed or contributes to the formation of a secondary air contaminant for which an Ambient Air Quality Standard has been adopted, or whose presence in the atmosphere will contribute to the violation of one or more Ambient Air Quality Standards. The following precursor-secondary air contaminant relationships shall be used for the purposes of this rule:

Table 3-4, Precursors

PRECURSOR	SECONDARY AIR CONTAMINANT
Volatile Organic Compounds	a. Photochemical oxidants (Ozone) b. The organic fraction of PM10
Nitrogen Oxides	a. Nitrogen dioxide b. The nitrate fraction of PM2.5 c. The nitrate fraction of PM10 d. Photochemical oxidants (Ozone)
Sulfur Oxides	a. Sulfur dioxide b. Sulfates c. The sulfate fraction of PM2.5 d. The sulfate fraction of PM10

3.35 Quarter: for a non-Seasonal Source, this is defined as a calendar quarter. For a Seasonal Source, a quarter is defined as the entire operating season.

3.36 Reasonable Further Progress: as defined by the federal Clean Air Act, Section 182(c)(2)(b).

3.37 Reconstructed Source: any Stationary Source undergoing reconstruction where the fixed capital cost of the new components exceeds 50% of the fixed capital cost of a comparable, entirely new Stationary Source. Fixed capital cost is the capital needed to provide depreciable components. Reconstructed Source cost shall include only the cost of all emission-producing equipment and associated integral activities at the

stationary source. A reconstructed Stationary Source shall be considered a new Stationary Source and not as a modification of an existing Stationary Source.

3.38 Routine Replacement Emissions Unit: routine replacement in whole or in part of any article, machine, equipment, or other contrivance with a valid District Permit to Operate provided that all of the following conditions are met:

3.38.1 The project does not result in a Federal Major Modification.

3.38.1.1 Routine maintenance or repair of an emissions unit or replacement of parts of an emissions unit shall not be considered a physical change in or change in the method of operation of a major source that would cause a federal major modification.

3.38.1.2 The replacement of a whole emissions unit that meets the definition of a replacement unit in paragraph 40 CFR 51.165(a)(1)(xxi) shall be treated as an existing emissions unit for purposes of assessing whether a project is a Federal Major Modification.

3.38.2 There is no increase in permitted emissions from the replacement unit(s). For replacements at major sources, "no increase in permitted emissions" as used in this definition also means no significant emissions increase according to the applicability calculations of 40 CFR 51.165(a)(2)(ii)(C). For the purposes of this definition, a Routine Replacement Emissions Unit is an existing emissions unit.

3.38.3 There is no increase in design capacity, unless an old part is no longer available in which case the replacement can result in a design capacity increase of up to 10%. No change to the permitted throughput or emission limits is authorized due to a change in design capacity as part of a replacement. Such changes shall require application for permit modification.

3.38.3.1 Permitted throughputs are throughput limits upon which emission calculations are, or could be, based.

3.38.3.2 If there are no throughput limiting conditions, permitted throughput shall be a throughput rate which affects emissions.

3.38.4 The replacement equipment performs the same function as the equipment being replaced.

3.38.5 The replacement does not constitute a Reconstructed Source (as defined by this rule) or Reconstruction (as defined by any applicable New Source Performance Standard). Reconstructed Source cost shall include only the cost of all emission-producing equipment and associated integral activities at the stationary source.

3.38.6 When the entire emissions unit is replaced as a routine replacement action, the emissions unit shall either have been addressed by a BARCT rule or shall use technology with a minimum control efficiency of at least 85%.

3.39 SB 288 Major Modification: as defined in 40 CFR Part 51.165 (as in effect on December 19, 2002) and part D of Title I of the CAA (as in effect on December 19, 2002). For the purposes of this definition, the SB 288 major modification thresholds for existing major sources are listed as follows:

Table 3-5, SB 288 Major Modification Thresholds

POLLUTANT	THRESHOLD (POUNDS PER YEAR)
VOC	50,000
NOx	50,000
PM10	30,000
SOx	80,000

3.40 Seasonal Source: any Stationary Source with more than 90% of its annual emissions occurring within a consecutive 120-day period.

3.41 Secondary Source Emissions: emissions which would occur as a result of the construction or operation of a new stationary source or modification, but do not come from the new stationary source or modification itself.

3.41.1 Secondary source emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification which causes the secondary source emissions.

3.41.2 Secondary source emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the new stationary source or modification.

3.41.3 Secondary source emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel.

3.42 Specific Limiting Condition (SLC): permit terms or conditions, which can be enforced in a practical manner, contained in Authorities to Construct and Permits to Operate and established pursuant to New Source Review provisions that restrict the total overall permitted emissions from two or more emissions units.

3.43 Stationary Source: any building, structure, facility, or installation which emits or may emit any affected pollutant directly or as a fugitive emission. Building, structure, facility or installation includes all pollutant emitting activities including emissions units which:

3.43.1 Are under the same or common ownership or operation, or which are owned or operated by entities which are under common control; and

3.43.2 Belong to the same industrial grouping either by virtue of falling within the same two-digit standard industrial classification code or by virtue of being part of a common industrial process, manufacturing process, or connected process involving a common raw material; and

3.43.3 Are located on one or more contiguous or adjacent properties; or

3.43.4 Are located on one or more properties wholly within either the Western Kern County Oil Fields or the Central Kern County Oil Fields or Fresno County Oil Fields and are used for the production of light oil, heavy oil or gas. Notwithstanding the provisions of this definition, light oil production, heavy oil production, and gas production shall constitute separate Stationary Sources.

3.44 Stationary Source Project: a single permitting action involving the modification, addition or shutdown of one or more emissions units. If any increase in emissions from a new or modified emissions unit is permitted based on emission reductions from one or more emissions units included in the stationary source project, the following condition must also be met:

3.44.1 The modification or shutdown resulting in the necessary emission reductions shall occur not later than the date of initial operation of the new or modified emissions unit. If the new or modified emissions unit is, in whole or in part, a replacement for an existing emissions unit at the same stationary source, the APCO may allow a maximum of 90 days as a start-up period for simultaneous operation of the existing emissions unit and the unit being replaced.

3.45 Temporary Replacement Emissions Unit (TREU): an emissions unit which is at a Stationary Source for less than 180 days in any twelve month period and replaces an existing emissions unit, with a valid District Permit to Operate, which is shutdown for maintenance or repair.

3.45.1 The Potential to Emit from a TREU must not exceed the Potential to Emit from the existing emissions unit.

3.45.2 If a TREU is used to replace a TREU, the combined time at the Stationary Source for the two TREU shall not exceed a total of 180 days in any twelve-month period.

3.45.3 An emissions unit not removed from the Stationary Source within 180 days is not a TREU.

4.0 Source Requirements

4.1 Best Available Control Technology (BACT): BACT requirements shall be triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless exempted pursuant to Section 4.2, BACT shall be required for the following actions:

4.1.1 Any new emissions unit or relocation from one Stationary Source to another of an existing emissions unit with a Potential to Emit exceeding 2.0 pounds in any one day;

4.1.2 Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds in any one day;

4.1.3 Any new or modified emissions unit(s), in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined in this rule.

4.2 BACT Exemptions: BACT shall not be required for the following:

4.2.1 CO emissions from a new or modified emissions unit at a Stationary Source with a post project Stationary Source Potential to Emit (SSPE2) of less than 200,000 pounds CO per year;

4.2.2 Cargo Carriers;

4.2.3 For existing facilities, the installation or modification of an emission control technique performed solely for the purpose of compliance with the requirements of District, State or Federal air pollution control laws, regulations, or orders, as approved by the APCO, shall be exempt from Best Available Control Technology for all air pollutants, provided all of the following conditions are met:

4.2.3.1 There shall be no increase in the physical or operational design of the existing facility, except for those changes to the design needed for the installation or modification of the emission control technique itself;

4.2.3.2 There shall be no increase in the permitted rating or permitted operating schedule of the permitted unit;

4.2.3.3 There shall be no increase in emissions from the stationary source that will cause or contribute to any violation of a National Ambient Air Quality Standard, Prevention of Significant Deterioration increment, or Air Quality Related Value in Class I areas; and

4.2.3.4 The project shall not result in an increase in permitted emissions or potential to emit of more than 25 tons per year of NOx, or 25 tons per year of VOC, or 15 tons per year of SOx, or 15 tons per year of PM10, or 50 tons per year of CO.

4.2.3.5 The project shall not constitute a federal major modification.

4.2.4 New emissions unit or modification of an existing emissions unit for voluntary reduction in emissions, for the sole purpose of generating emission reduction credits. This exemption applies only to the pollutant for which emission reduction credits are obtained. BACT may be required for other affected pollutants;

4.2.5 A Temporary Replacement Emissions Unit;

4.2.6 A Routine Replacement Emissions Unit; or

4.2.7 Transfer of location of emissions units within the same stationary source.

4.3 Adjusted Increase in Permitted Emissions (AIPE) Calculations: Adjusted Increase in Permitted Emissions shall be calculated as:

$$AIPE = PE2 - HAPE$$

Where:
AIPE = Adjusted Increase in Permitted Emissions, pounds per day
PE2 = the emissions units post project Potential to Emit, pounds per day
HAPE = the emissions unit's Historically Adjusted Potential to Emit, pounds per day

4.4 Historically Adjusted Potential to Emit (HAPE) Calculations: Historically Adjusted Potential to Emit shall be calculated as:

$$HAPE = PE1 \times (EF2 / EF1)$$

Where:
PE1 = The emissions unit's Potential to Emit prior to modification or relocation
EF2 = The emissions unit's permitted emission factor for the pollutant after modification or relocation. If EF2 is greater than EF1 then EF2/EF1 shall be set to 1
EF1 = The emissions unit's permitted emission factor for the pollutant before the modification or relocation

4.5 District Emission Offset Requirements:

4.5.1 If emission offset requirements are triggered pursuant to Section 4.5.3, emission offsets shall be provided for net emissions increases resulting from a project. Offset quantities shall be calculated pursuant to Section 4.7.

4.5.2 For Stationary Sources with a quarterly Potential to Emit which remains constant throughout the year, the amount shall be calculated in pounds per year. For Stationary Sources with quarterly Potential to Emit that is not constant throughout the year, and for Seasonal Sources the amount shall be calculated in pounds per quarter.

4.5.3 Offset requirements shall be triggered on a pollutant-by-pollutant basis. Unless exempted pursuant to Section 4.6, offsets shall be required if the post-project Stationary Source Potential to Emit (SSPE2) equals or exceeds the following offset threshold levels:

Table 4-1, Emissions Offset Threshold Levels

POLLUTANT	SSPE2 (POUNDS /YEAR)
VOC	20,000
NOx	20,000
CO	200,000
SOx	54,750
PM10	29,200

4.5.4 Offsets shall be required for PM2.5 and PM2.5 precursor emission increases for such increases that constitute new major sources or federal major modifications.

4.6 District Emission Offset Exemptions: District emission offsets, pursuant to Section 4.5, shall not be required for the following:

4.6.1 Increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards;

4.6.2 Emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Equipment exempted by this section shall maintain a written record of hours of operation and shall have permit conditions limiting non-emergency operation;

4.6.3 Portable equipment which is registered as such in accordance with the provisions of Rule 2280 (Portable Equipment Registration) or the Statewide Portable Equipment Registration Program (California Code of Regulation Title 13, Article 5, Sections 2450-2465), or equipment registered in accordance with the provisions of Rule 2250 (Permit-Exempt Equipment Registration);

4.6.4 On-site soil or groundwater decontamination performed by, under the jurisdiction of, or pursuant to the requirements of an authorized health officer, agricultural commissioner, fire protection officer, or other authorized government officers, provided emissions do not exceed 4,000 pounds per year of any affected pollutant from all emissions units associated with decontamination project;

4.6.5 A Temporary Replacement Emissions Unit.

4.6.6 A transfer of location of an entire Stationary Source within the District, under the same ownership and provided:

4.6.6.1 The Potential to Emit of any affected pollutant will not be greater at the new location than at the previous location when all emissions units are operated at the same permitted conditions; and

4.6.6.2 BACT is applied to all emissions units with a Potential to Emit exceeding 2.0 pounds per day; and

4.6.6.3 The transferred Stationary Source is not added to an existing Stationary Source.

4.6.7 A transfer of location of an emissions unit from one Stationary Source to another within the District, under the same ownership and provided:

4.6.7.1 The Potential to Emit of any affected pollutant will not be greater at the new location than at the previous location when all emissions units are operated at the same permitted conditions, and

4.6.7.2 The offsets that would be otherwise required for the unit at the new location have been provided for the emissions unit previously.

4.6.8 For existing facilities, the installation or modification of an emission control technique performed solely for the purpose of compliance with the requirements of District, State or Federal air pollution control laws, regulations, or orders, as approved by the APCO, shall be exempt from offset requirements for all air pollutants provided all of the following conditions are met:

4.6.8.1 There shall be no increase in the physical or operational design of the existing facility, except for those changes to the design needed for the installation or modification of the emission control technique itself;

4.6.8.2 There shall be no increase in the permitted rating or permitted operating schedule of the permitted unit;

4.6.8.3 There shall be no increase in emissions from the stationary source that will cause or contribute to any violation of a National Ambient Air Quality Standard, Prevention of Significant Deterioration increment, or Air Quality Related Value in Class I areas; and

4.6.8.4 The project shall not result in an increase in permitted emissions or potential to emit of more than 25 tons per year of NOx, or 25 tons per year of VOC, or 15 tons per year of SOx, or 15 tons per year of PM10, or 10 tons per year of PM2.5, or 50 tons per year of CO.

4.6.9 For Agricultural Sources, increases in affected pollutants for that source if emissions reductions from that source would not meet the criteria for real, permanent, quantifiable, and enforceable emission reductions.

4.6.9.1 In no case shall the offset exemption in Section 4.6.9 apply to an agricultural source that is also a major source for the pollutant for which the offset exemption is sought.

4.6.10 NOx emissions, if the project is a federal major modification or new major source for NOx emissions.

4.6.11 VOC emissions, if the project is a federal major modification or new major source for VOC emissions.

4.7 District Offset Quantity (DOQ) Calculations:

4.7.1 For pollutants with a pre-project Stationary Source Potential to Emit (SSPE1) greater than the emission offset threshold levels, emission offsets shall be provided for:

4.7.1.1 All increases in Stationary Source emissions, calculated as the sum of differences between the post-project Potential to Emit (PE2) and the Baseline Emissions (BE) of all new and modified emissions units, plus

4.7.1.2 All increases in Cargo Carrier emissions.

4.7.2 For pollutants with a pre-project Stationary Source Potential to Emit (SSPE1) less than or equal to the offset threshold levels, emission offsets shall be provided for:

4.7.2.1 All increases in Stationary Source emissions above the offset trigger levels, calculated as the difference between the SSPE2 and the offset trigger level, plus

4.7.2.2 All increases in Cargo Carrier emissions.

4.7.3 The quantity of offsets calculated pursuant to Sections 4.7.1 and 4.7.2 shall be multiplied by the applicable Offset Ratio to determine the final quantity of offsets required.

4.7.4 PM10 Emissions: In determining the quantity of required PM10 offsets, the Total Suspended Particulate Matter (TSP) emissions for which full offsets have been previously provided shall not be recalculated as PM10.

4.8 Federal Emission Offset Requirements:

4.8.1 Offset Requirements for Federal Nonattainment Pollutants and Their Significant Precursors:

4.8.1.1 The emission increases for a new major source or a federal major modification shall be offset with internal emission reductions (IERs) or other actual emission reductions (AERs) that are surplus at the time of ATC issuance.

4.8.1.2 Offset quantities shall be calculated pursuant to Section 4.8.4.

4.8.1.3 Offset requirements shall be triggered on a pollutant-by-pollutant basis.

4.8.1.4 AERs from one or more sources may be used, alone or in combination with IERs, in order to satisfy offset requirements.

4.8.1.5 AERs achieved by shutting down an existing emissions unit or curtailing production or operating hours may only be credited for offsets if such reductions meet the following requirements:

4.8.1.5.1 The shutdown or curtailment occurred after the last day of the base year for the attainment plan for the specific pollutant; or

4.8.1.5.2 The projected emissions inventory used to develop the attainment plan explicitly includes the emissions from such previously shutdown or curtailed emissions units. However, in no event may credit be given for shutdowns that occurred before August 7, 1977.

4.8.1.6 Emission reductions achieved by shutting down an existing emissions unit or curtailing production or operating hours that do not meet the requirements in Section 4.8.1.5.1 or Section 4.8.1.5.2 may be used as offsets if the shutdown or curtailment occurred on or after the date the application for the construction permit utilizing the offsets is filed; or

4.8.1.7 The applicant can establish that the proposed new emissions unit is a replacement for the shutdown or curtailed emissions unit, and the emissions reductions achieved by the shutdown or curtailment are surplus at time-of-use, permanent, quantifiable and enforceable.

4.8.1.8 Except for NOx and VOC emissions, offsets may be satisfied with the Creditable Actual Emission Reductions from the Carryover Balance or Running Balance according to the requirements of Section 7.0.

4.8.2 Federal Offset Exemptions:

The offset requirements of Section 4.8.1 shall not be applicable to a modification of an existing source if such modification is solely for the purpose of compliance with the NOx or VOC requirements of District, State or Federal air pollution control laws, regulations, or orders, as approved by the APCO.

4.8.3 Timing:

4.8.3.1 AERs used to satisfy an offset requirement must be federally enforceable prior to the issuance of the Authority to Construct, which relies on the emission reductions.

4.8.3.2 Except as provided in Section 4.8.3.3, the decrease in actual emissions used to generate AERs or IERs must occur no later than the commencement of operation of the new or modified major source.

4.8.3.3 If the new emissions unit is a replacement for an emissions unit that is being shutdown in order to provide the necessary offsets, the APCO may allow up to 90 days for a start-up period of the new emissions unit before the existing emissions unit is required to cease operation.

4.8.4 Federal Offset Quantity (FOQ) shall be determined in accordance with the following:

4.8.4.1 The unit of measure for offsets, AERs, and IERs shall be pounds per quarter. All calculations and transactions shall use emission rate values rounded to the nearest pound.

4.8.4.2 The quantity of AERs or IERs required shall be calculated as the product of the amount of increased emissions, as determined in accordance with Section 4.8.4.3, and the offset ratio, as determined in accordance with Section 4.9.

4.8.4.3 The amount of increased emissions shall be determined by summing the difference between the post-project potential to emit and the federal baseline emissions, as defined in Section 3.19, for each emissions unit.

4.9 Offset Ratios: For offset calculations, the offset ratio shall be as stated below:

4.9.1 For NOx and VOC offsets required for new major sources and federal major modifications, the offset ratio for IERs shall be 1.3; otherwise, the offset ratio shall be 1.5;

4.9.2 For PM2.5 and PM2.5 precursor offsets for new major sources and federal major modifications, the offset ratio shall be 1.0;

4.9.3 The requirements of Section 4.9.1 shall not apply if the District demonstrates to the satisfaction of the federal Environmental Protection Agency that all major sources of NOx and VOC in the District are equipped with federal BACT, as defined in CAA Section 169(3). After EPA approval of such a demonstration, the offset ratios listed in Table 4-2 shall apply for new major sources and federal major modifications, except that where the original location of the offsets is at the same stationary source as the new or modified emissions unit, the offset ratio shall be 1.2.

4.9.4 For all other projects not specified above, the offset ratio shall be as shown in Table 4-2:

Table 4-2, Offset Ratio

ORIGINAL LOCATION OF EMISSION OFFSETS	OFFSET RATIO
at the same Stationary Source as the new or modified emissions unit	1.0
within 15 miles of the new or modified emissions unit's Stationary Source	1.2 for Non-Major Sources 1.3 for Major Sources
15 miles or more from the new or modified emissions unit's Stationary Source	1.5

4.10 Pre-project Stationary Source Potential to Emit (SSPE1) shall be calculated, on a pollutant-by-pollutant basis, as the sum of the following:

4.10.1 The Potential to Emit from all emissions units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source.

4.10.1.1 For an emissions unit with both a valid ATC and a PTO, or an emissions unit with multiple valid ATCs, use the ATC or PTO with the highest potential emission limits.

4.10.1.2 For emissions units subject to an SLC, the Potential to Emit shall be based on the overall Potential to Emit emission limit for all emissions units covered by the SLC and not the sum of the individual Potential to Emit of each emissions unit.

4.10.2 The quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. This quantity includes all ERC held as certificates and all emission reduction credits that have been sold or transferred. Reductions shall be added to the SSPE1 as positive values.

4.11 Post-project Stationary Source Potential to Emit (SSPE2) shall be calculated, on a pollutant-by-pollutant basis, as the sum of the following:

4.11.1 The Potential to Emit from all emissions units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source, except for emissions units proposed to be shutdown as part of a Stationary Source Project.

4.11.1.1 The Potential to Emit of the post-project ATC will be used for new or modified emissions units, provided that the ATC will include new conditions canceling the existing ATC or PTO for those units, otherwise use the ATC or PTO with the highest potential emissions.

4.11.1.2 For emissions units subject to an SLC, the Potential to Emit shall be based on the overall Potential to Emit limit for all emissions units covered by the SLC and not the sum of the individual Potential to Emit of each emissions unit.

4.11.2 The quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. This quantity includes all ERCs held as certificates and all ERCs that have been sold or transferred. Reductions shall be added to the SSPE2 as positive values.

4.12 Calculations involving PM10 emissions

4.12.1 For existing Stationary Sources for which particulate matter emissions have been calculated as Total Suspended Particulate (TSP), the PM10 emissions shall be recalculated from TSP values using PM10 emission factors or speciation data.

4.12.2 In the absence of PM10 emissions factors or speciation data, assume 50% of the TSP is PM10.

4.12.3 If the applicant has previously provided full offsets for total suspended particulate matter emissions, those total suspended particulate matter emissions need not be recalculated as PM10, for the purpose of determining the quantity of offsets.

4.13 Actual Emissions Reductions (AER) Calculations: Actual Emissions Reductions shall be calculated, on a pollutant-by-pollutant basis, as follows:

$$AER = HAE - PE2$$

Where:
HAE = Historic Actual Emissions
PE2 = Post-project Potential to Emit

4.13.1 Prior to banking, AER shall be discounted by 10 percent (10%) for an Air Quality Improvement Deduction, and shall comply with all applicable provisions of Rule 2301 (Emission Reduction Credit Banking).

4.14 Additional Offset Requirements: Offsets obtained subject to this rule shall comply with the following provisions:

4.14.1 Major Source shutdowns or permanent curtailments in production or operating hours of a Major Source may not be used as offsets for emissions from a Major Source, a Federal Major Modification, or an SB 288 Major Modification, unless the ERC, or the emissions from which the ERC are derived, has been included in an EPA-approved attainment plan.

4.14.2 Offsets from another district may be used only if the source of the offsets is within 50 miles of the proposed emissions increases and the APCO has reviewed the permit conditions issued by the district in which the proposed offsets are obtained and certifies that such offsets meet the requirements of this rule and CH&SC Section 40709.6.

4.14.3 Interpollutant offsets:

4.14.3.1 Except for ozone precursors emitted from new major sources or federal major modifications, interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.

4.14.3.1.1 In no case shall exempt compounds or the other compounds excluded from the definition of VOC be used as offsets for VOC.

Interpollutant offsets between PM10 and PM10 precursors may be allowed.

4.14.3.1.2 PM10 emissions shall not be allowed to offset NOx or reactive organic compound emissions in ozone nonattainment areas, nor be allowed to offset SO2 emissions in sulfate nonattainment areas.

4.14.3.1.3 Interpollutant offsets between NOx and VOC may be allowed.

4.14.3.2 Interpollutant offsets between PM2.5 and PM2.5 precursors are allowed at specific ratios as established by US EPA, or as approved into the State Implementation Plan by the US EPA.

4.14.4 Actual Emissions Reductions (AER) used as offsets must have occurred during the same calendar quarter as the emissions increases being offset, except as allowed pursuant to Sections 4.14.6 through 4.14.9.

4.14.5 AER used as offsets for a Seasonal Source must have occurred during the same time period as the proposed source will operate, except as allowed pursuant to Sections 4.14.6 through 4.14.9.

4.14.6 AER used as offsets for a biomass-fired power facility may have occurred during any quarter.

4.14.7 AER for PM emissions that occurred from emission reductions occurring October through March, inclusive, may be used to offset increases in PM emissions during any period of the year.

4.14.8 AER for NOx and VOC emissions that occurred from emission reductions occurring April through November may be used to offset increases in NOx and VOC emissions during any period of the year.

4.14.9 AER for CO emissions that occurred from emission reductions occurring November through February may be used to offset increases in CO emissions during any period of the year.

4.14.10 AER used as offsets for new and modified Major Sources must be obtained from an area:

4.14.10.1 That has a nonattainment classification that is equal to or higher than the area in which the new or modified Major Source is located, and

4.14.10.2 Where emissions contribute to a violation of a national Ambient Air Quality Standard in the area in which the new or modified Major Source is located.

4.14.11 Offsets required as a condition of an Authority to Construct or a Permit to Operate shall commence not later than the date of initial operation of the new or modified emissions unit.

4.14.11.1 If the new or modified emissions unit is, in whole or in part, a replacement for an existing emissions unit at the same stationary source, the APCO may allow a maximum of 90 days as a start-up period for simultaneous operation of the existing emissions unit and the unit being replaced.

4.14.12 Nothing in this rule shall be construed as requiring AER used as NSR offsets to be discounted at time of use, except for the additional offsets as required by Sections 4.8, 4.9, 4.14.3, and as described in Section 7.0.

4.15 Ambient Air Quality Standards:

4.15.1 Emissions from a new or modified Stationary Source shall not cause or make worse the violation of an Ambient Air Quality Standard. In making this determination, the APCO shall take into account the increases in minor and secondary source emissions as well as the mitigation of emissions through offsets obtained pursuant to this rule. Modeling used for the purposes of this rule shall be consistent with the requirements contained in the most recent edition of EPA's "Guideline on Air Quality Models" unless the APCO finds such model is inappropriate for use. After making such a finding, the APCO may designate an alternative model only after allowing for public comments and only with the concurrence of the ARB or the EPA. Credit shall not be given for stacks higher than that dictated by good engineering practice or by any other dispersion technique except as provided in 40 CFR 51.118(b), where the definitions of 40 CFR 51.100(hh) through (kk) are applicable.

4.15.1.1 At the discretion of the APCO, a new or modified source which is not subject to the public noticing requirements of Section 5.4 shall be exempted from the requirements of Section 4.15.1.

4.16 Additional Requirements for New Major Sources and Federal Major Modifications

4.16.1 Alternative siting: An applicant for a proposed stationary source project that will result in a new major source or federal major modification shall prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq. of the Public Resources Code.

4.16.2 Compliance by Other Owned, Operated, or Controlled Source: An applicant for a proposed stationary source project that will result in a new major source or federal major modification shall demonstrate to the satisfaction of the APCO that all major sources owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in California which are subject to emission

limitations are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

4.16.3 Impact on Visibility of a Mandatory Class I Federal Area:

4.16.3.1 The APCO shall provide written notice and conduct any necessary review and consultation with the Federal Land Manager (FLM) regarding any new major source or federal major modification that may impact visibility in any Mandatory Class I Federal Area, in accordance with the applicable requirements of 40 CFR 51.307.

4.16.3.2 After consultation with the FLM, the APCO may require monitoring of visibility in any Mandatory Class I Federal Area, near the proposed new major source or federal major modification for such purposes and by such means as the APCO deems necessary and appropriate.

4.16.3.3 After consultation with the FLM, the APCO may deny any Authority to Construct if the APCO and the FLM determine, that the project would have an adverse impact on visibility, as defined in 40 CFR 52.21(b)(29).

4.16.4 The approval of a proposed new major source or federal major modification shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the SIP and other local, state, and federal requirements.

4.16.5 If any source or modification becomes a federal major modification or major source as defined in Sections 3.21 and 3.28 solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on a capacity of the source or modification to emit a federal nonattainment pollutant or its precursor, such as a restriction on hours of operation, then the requirements of this rule shall apply to such a source or modification as though construction had not yet commenced on the source or modification.

5.0 Administrative Requirements

The administrative requirements of Sections 5.1 through 5.7, inclusive, shall be applied to all applications for a new or modified emissions unit except for power plants proposed to be constructed in the District and for which a Notice of Intention (NOI) or Application for Certification (AFC) has been accepted by the California Energy Commission. For such power plants, the administrative requirements of Section 5.8 shall apply.

5.1 Complete Application: The APCO shall determine whether the application is complete not later than 30 days after receipt of the application, or after such longer time as both the applicant and the APCO may agree.

5.1.1 If the APCO determines that the application is not complete, the applicant shall be notified in writing of the decision specifying the information required. Upon receipt of any resubmittal of the application, a new 30-day period to determine completeness shall begin.

5.1.2 Completeness of an application or resubmitted application shall be evaluated on the basis of the information requirements set forth in the District Rules and Regulations as they exist on the date on which the application or resubmitted application is received.

5.1.3 Upon determination that the application is complete, the APCO shall notify the applicant in writing.

5.1.4 The APCO may, during the processing of the application, request an applicant to clarify, amplify, correct, or otherwise supplement the information submitted in the application.

5.2 Preliminary Decision: Following acceptance of an application as complete, the APCO shall perform the evaluations required to determine compliance with this rule and all other District rules and make a preliminary written decision as to whether an Authority to Construct should be approved, conditionally approved, or disapproved.

5.2.1 The APCO shall deny any Authority to Construct if the APCO finds that the subject of the application would not comply with the standards set forth in this rule or any other District rule.

5.2.2 The decision shall be supported by a succinct, written analysis.

5.3 Final Action:

5.3.1 Within 180 days after acceptance of an application as complete, or within 180 days after the lead agency has approved the project under the California Environmental Quality Act, whichever occurs later, the APCO shall take final action on the application after considering all written comments.

5.3.2 The APCO shall not take final action on a new major source or federal major modification if the EPA has determined that the applicable implementation plan is not being adequately implemented for the nonattainment area.

5.4 Public Notification and Publication Requirements: The APCO shall provide public notification and publication for the following types of applications:

5.4.1 New Major Sources, Federal Major Modifications, and SB 288 Major Modifications.

5.4.2 Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one affected pollutant;

5.4.3 Modifications that increase the Stationary Source Potential to Emit (SSPE1) from a level below the emissions offset threshold level to a level exceeding the emissions offset threshold level for one or more pollutants;

5.4.4 New Stationary Sources with post-project Stationary Source Potential to Emit (SSPE2) exceeding the emissions offset threshold level for one or more pollutants;

5.4.5 Any permitting action resulting in a Stationary Source Project Increase in Permitted Emissions (SSIPE) (calculated as the difference between the SSPE2 and the SSPE1), exceeding 20,000 pounds per year for any one pollutant;

5.4.6 Modifications of non-major sources that increase the stationary source's potential to emit (consistent with the requirements in Sections 3.28.1, 3.28.2, and 3.28.3) from below 80% of the major source threshold to a level equal to or exceeding 80% of the major source threshold for one pollutant or more.

5.5 Public Notification and Publication Actions: For the types of applications listed in Section 5.4, the APCO shall perform the following actions:

5.5.1 Within ten (10) calendar days following the preliminary decision the APCO shall electronically publish a notice on the District's website, including a copy of the draft permit, stating the preliminary decision, noting how pertinent information can be obtained, and inviting written public comment for a 30 day period following the date of publication.

5.5.2 No later than the date of publication, the APCO shall transmit to the applicant its preliminary written decision, the analysis, and a copy of the notice submitted for publication.

5.5.3 No later than the date of publication, the APCO shall transmit to the ARB and to any person who requests such information, its preliminary written decision, the analysis, and a copy of the notice submitted for publication. For New Major Sources, Federal Major Modifications, SB 288 Major Modifications, and projects subject to Section 5.4.6, the APCO shall also transmit the preliminary written decision and supporting documents to the EPA.

5.5.4 No later than the time the notice of the preliminary decision is published, the APCO shall make available for public inspection at the District office the information submitted by the applicant and the analysis.

5.5.5 The APCO shall provide written notice of the final action to the applicant, and the ARB, and shall electronically publish such notice on the District's website, except that for an application not subject to Section 5.4, the APCO shall not be subject to this section. In such a case, the applicant shall receive notification as provided in Rule 2040 (Applications). For new Major

Sources, Federal Major Modifications, SB 288 Major Modifications, and projects subject to Section 5.4.6, the APCO shall also transmit written notice of the final action to the EPA.

5.5.6 No later than the time of notice of final action is published on the District's website, the APCO shall make available for public inspection at District offices a copy of the notice submitted for publication and all supporting documents.

5.6 Authority to Construct (ATC) - General Conditions

5.6.1 An ATC shall not be issued unless the new or modified source complies with the provisions of this rule and all other applicable District Rules and Regulations.

5.6.2 An ATC shall require that the new or modified source be built according to the specifications and plans contained in the application.

5.6.3 An ATC shall include all those conditions which the APCO deems necessary to assure construction and operation in the manner assumed in making the analysis to determine compliance with this rule and all other applicable District rules.

5.6.4 An ATC shall include all those conditions relating to the satisfaction of the offset requirements of this rule.

5.6.5 An ATC issued for an emissions unit that relies on reduction in emissions from other units included in the Stationary Source Project, must include a condition that requires initiating and completing construction on those units that provide the reduction prior to commencing operation of the unit with an increase in emissions.

5.6.5.1 If the new or modified emissions unit is, in whole or in part, a replacement for an existing emissions unit at the same stationary source, the APCO may allow a maximum of 90 days as a start-up period for simultaneous operation of the existing emissions unit and the unit being replaced.

5.7 Permit to Operate (PTO) - General Conditions

5.7.1 A PTO shall require that the new source or modification be operated in the manner assumed in making the analysis to determine compliance with this rule and as conditioned in the Authority to Construct.

5.7.2 A PTO shall include daily emissions limitations and other enforceable conditions which reflect applicable emission limits including the offset requirements.

5.7.3 The APCO shall determine if the applicant has complied with all the conditions in the ATC. The APCO may allow conditions which have not been met at the time the PTO is issued to be incorporated into the Permit to Operate, provided that compliance with that condition is demonstrated by a specified date.

5.7.4 Any source which provides offsets shall be subject to enforceable permit conditions containing specific operational and emissions limitations, which ensure that the emissions reductions will be provided in accordance with the provisions of this rule and shall continue for the reasonably expected life of the proposed source. Where the source of offsets is not subject to a permit, a written contract shall be required between the applicant and the owner of such source, which contract, by its terms, shall be enforceable by the APCO. The permit and contract shall be submitted to the ARB to be forwarded to the EPA as part of the State Implementation Plan. A violation of the emission limitation provisions of any such contract shall be chargeable to the applicant.

5.7.5 Offsets required as a condition of an ATC or a PTO shall commence not later than the date of initial operation of the new or modified source,

5.7.5.1 If a new or modified Stationary Source is, in whole or in part, a replacement for an existing Stationary Source on the same or contiguous property the APCO may allow a maximum of 90 days as a start-up period for simultaneous operation of the existing Stationary Source and the new or replacement source.

5.8 Power plants which will be licensed by the California Energy Commission: The administrative requirements of this section shall be applied to all power plants proposed to be constructed in the District and for which a Notice of Intention (NOI) or Application for Certification (AFC) has been accepted by the California Energy Commission. The APCO may apply for reimbursement of all costs incurred, including lost fees, in order to comply with the provisions of this section.

5.8.1 Intent to Participate and Preliminary Report: Within 14 days of receipt of a NOI, the APCO shall notify the ARB and the California Energy Commission of the APCO's intent to participate in the NOI proceeding. If the APCO chooses to participate in the NOI proceeding, the APCO shall prepare and submit a report to the ARB and the California Energy Commission prior to the conclusion of the non-adjudicatory hearings specified in Section 25509.5 of the Public Resources Code. The report shall include at least the following:

5.8.1.1 A preliminary specific definition of BACT for the proposed facility.

5.8.1.2 A preliminary discussion of whether there is substantial likelihood that the requirements of this rule and all other District rules can be satisfied by the proposed facility.

5.8.1.3 A preliminary list of conditions which the proposed facility must meet in order to comply with this rule or any other applicable District rules. The preliminary determinations contained in the report shall be as specific as possible within the constraints of the information contained in the NOI.

5.8.2 Equivalency of Application for Certification to Application for Authority to Construct: The APCO shall consider an Application for Certification (AFC) to be equivalent to an application for an Authority to Construct, and subject, as such, to all definitions and requirements of this rule.

5.8.3 Upon receipt of an AFC for a power plant, the APCO shall conduct a Determination of Compliance review. This review shall determine whether an AFC is complete, and within 20 calendar days of receipt of the AFC, the APCO shall so inform the California Energy Commission and the applicant in writing.

5.8.3.1 If the APCO determines that the application is not complete, the information required shall be specified, and the AFC shall be returned to the applicant for resubmittal. Upon receipt of any resubmittal of the application, a new 20-day period to determine completeness shall begin.

5.8.3.2 Completeness of an application or resubmitted application shall be evaluated on the basis of the information requirements set forth in District Rules and Regulations as they exist on the date on which the application or resubmitted application is received.

5.8.4 The APCO may request from the applicant any information necessary for the completion of the Determination of Compliance review. If the APCO is unable to obtain the information, the APCO may petition the presiding Commissioner of the California Energy Commission for an order directing the applicant to supply such information.

5.8.5 Within 180 days of accepting an AFC as complete, the APCO shall make a preliminary written decision as to whether a Determination of Compliance Certification should be approved, conditionally approved, or disapproved. The APCO shall deny any Determination of Compliance Certification if the APCO finds that the subject of the application would not comply with the standards set forth in this rule or any other District rule. The decision shall be supported by a succinct, written analysis.

5.8.6 Notification and Publication actions shall be conducted according to the requirements of Section 5.5.

5.8.7 Within 240 days after acceptance of an application as complete, the APCO, after considering all written comments, shall take final action on the AFC, which action shall consist of the following:

5.8.7.1 The APCO, if all requirements of this rule are met, shall issue and submit to the California Energy Commission a Determination of Compliance, or advise the Commission that a Determination of Compliance cannot be issued.

5.8.7.2 Public inspection of final action documents shall be provided for in accordance with Section 5.5.6.

5.8.8 Equivalency of Determination of Compliance to Authority to Construct: A Determination of Compliance shall confer the same rights and privileges as an Authority to Construct provided that the California Energy Commission approves the Application for Certification and the certificate granted by the Commission includes all conditions of the Determination of Compliance.

5.8.9 The APCO shall issue a Permit to Operate to any applicant receiving a certificate from the California Energy Commission pursuant to this rule provided that the construction or modification is in compliance with all conditions of the Certification and of the Determination of Compliance, and provided that the Permit to Operate includes the conditions prescribed in Section 5.7.

5.9 Enhanced Administrative Requirements

Application for a Certificate of Conformity (COC) pursuant to Section 6.0, shall be subject to the following enhanced administrative requirements in addition to any other applicable administrative requirements of Section 5.0:

5.9.1 New Sources and Significant Permit Modifications

5.9.1.1 Public Notification: The APCO shall provide a written notice of the proposed permit and, upon request, copies of the APCO's analysis to interested parties. Interested parties shall include affected states, ARB and persons who have requested in writing to be notified. The notice shall also be given by electronic publication on the District's website and by any other means if necessary to assure adequate notice to the affected public. The public shall be given 30 days from the date of publication to submit written comments on the APCO's proposed action.

5.9.1.2 The notice shall provide the following information:

5.9.1.2.1 The identification of the source, the name and address of the permit holder, and the activities and emissions change involved in the permit action;

5.9.1.2.2 The name and address of the APCO, and the name and telephone number of District staff to contact for additional information;

5.9.1.2.3 The availability, upon request, of a statement that sets forth the legal and factual basis for the proposed permit conditions;

5.9.1.2.4 The location where the public may inspect the Complete Application, the APCO's analysis, the proposed permit, and all relevant supporting materials;

5.9.1.2.5 A statement that the public may submit written comments regarding the proposed decision within at least 30 days from the date of publication and a brief description of commenting procedures; and

5.9.1.2.6 A statement that members of the public may request the APCO or his designee to preside over a public hearing for the purpose of receiving oral public comment, if a hearing has not already been scheduled. The APCO shall provide notice of any public hearing scheduled to address the proposed decision at least 30 days prior to such hearing.

5.9.1.3 The APCO shall provide a written response to persons or agencies that submitted written comments which are postmarked by the close of the public notice and comment period. All written comments and responses to such comments shall be kept on file at the District office and made available upon request.

5.9.1.4 A copy of the Complete Application, the APCO's analysis and the proposed permit shall be made available at District offices for public review and comment during normal business hours. The APCO's analysis shall include a statement that sets forth the legal and factual basis for the proposed permit conditions, including references to the applicable statutory and regulatory provisions.

5.9.1.5 The APCO shall provide written notice to the EPA of the proposed decision along with copies of the proposed permit, the APCO's analysis, the public notice submitted for publication, and all necessary supporting information.

5.9.1.6 If the EPA does not object pursuant to Section 5.9.1.9, the APCO may issue the final permit.

5.9.1.7 If the EPA does not object in writing to the APCO's preliminary decision during the EPA's 45 day review period, any person may petition the EPA within 60 days after the expiration of the EPA's 45 day review period. Any such petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period, unless the petitioner

demonstrates to the EPA that it was impracticable to raise such objections within such period, or unless grounds for such objections arose after such period. Petitions shall be based on the compliance of the permit provisions with applicable requirements.

5.9.1.8 Within 180 days after acceptance of an application as complete, or within 180 days after the lead agency has approved the project under the California Environmental Quality Act, whichever occurs later, the APCO shall take final action on the application after considering all written comments.

5.9.1.9 The APCO shall not issue a permit if the EPA objects to its issuance in writing within 45 days of receipt of the APCO's notice of preliminary decision on the proposed permit.

5.9.1.9.1 Any EPA objection shall include a statement of the EPA's reasons for objection and a description of the terms and conditions that the permit must include to respond to the objections. The EPA shall provide the permit applicant a copy of the objection.

5.9.1.9.2 If the APCO fails, within 90 days after the date of EPA's objection, or within 180 days from the date the application was deemed complete plus any extension allowed by the state law, whichever is sooner, to revise and submit a proposed permit in response to the objection, the APCO shall not issue a Certificate of Conformity to the 40 CFR Part 70 procedural requirements.

5.9.1.9.3 If the EPA objects to the permit as a result of a public petition, the APCO shall not issue the permit until EPA's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day review period and prior to an EPA objection. If the APCO has issued a permit prior to receipt of an EPA objection, the EPA will modify, terminate, or revoke such permit, and shall do so consistent with procedures in Section 70.7(g)(4) or (5)(i) and (ii) of the 40 CFR regulations, and the APCO may thereafter reissue only a revised permit that satisfies EPA objection.

5.9.1.9.4 EPA objection shall be limited to compliance with applicable requirements and the requirements of 40 CFR Part 70.

5.9.2 Minor Permit Modifications

5.9.2.1 Within 5 working days after the receipt of a Complete Application for a minor permit modification, the APCO shall provide notification of the proposed permit modification to the EPA, affected states, and interested parties pursuant to Section 5.9.1.1.

5.9.2.2 The APCO shall not issue a final permit modification until after a 45-day period review of the proposed permit modification by EPA or until EPA has notified the APCO that EPA will not object to issuance of the permit modification, whichever is first.

5.9.2.3 Within 90 days after APCO's receipt of an application for a minor permit modification or 15 days after the end of the EPA's 45-day review, whichever is later, the APCO shall do one of the following:

5.9.2.3.1 Issue the permit as proposed;

5.9.2.3.2 Deny the permit modification application;

5.9.2.3.3 Determine that the requested modification does not meet the minor permit modification criteria and should be reviewed pursuant to the administrative requirements for significant permit modifications; or

5.9.2.3.4 Revise the draft permit modification and transmit the new proposed permit modification to EPA and the affected states.

6.0 Certification of Conformity (COC)

A new or modified source subject to the requirements of Rule 2520 may choose to apply for a Certificate of Conformity with the procedural requirements of 40 CFR Part 70. A Certificate of Conformity will allow changes authorized by the Authority to Construct to be incorporated into the Part 70 permit as administrative permit amendments.

6.1 The APCO will issue a written Certificate of Conformity with the procedural requirements of 40 CFR 70.7 and 70.8, and with the compliance requirements of 40 CFR 70.6(8)(c), if the following conditions are met:

6.1.1 The Authority to Construct is issued in conformance with the Enhanced Administrative Requirements of Section 5.9 of this rule;

6.1.2 The content of the Authority to Construct issued by the APCO complies with the requirements set forth in Section 9.0 of District Rule 2520 (Federally Mandated Operating Permits);

6.1.3 An application for a Certificate of Conformity with the requirements of 40 CFR Part 70 is submitted with the application for Authority to Construct. The content of application for the Certificate of Conformity must comply with the requirements of Sections 7.1 of District Rule 2520 (Federally Mandated Operating Permits);

6.1.4 The Authority to Construct contains a statement of conformity with the requirements of 40 CFR Part 70;

6.1.5 EPA has not objected to the issuance of the Authority to Construct, or EPA's objections have been resolved to the satisfaction of EPA Administrator; and

6.1.6 The Part 70 operating permit being issued will contain the federally enforceable requirements contained in the Authority to Construct.

6.2 The (COC) with the procedural requirements of 40 CFR Part 70 is valid as long as the Authority to Construct with which it was issued is valid.

6.3 Modifications to an Authority to Construct for which a (COC) has been issued are subject to the administrative requirements of Section 11.0 of District Rule 2520 that apply to permit modifications and changes, as well as the requirements of all District Rules that apply to modifications of Authorities to Construct.

7.0 Federal Offset Equivalency Demonstration for PM10, PM2.5, and SOx

The purpose of Section 7.0 is to provide requirements for the District to demonstrate on an individual ATC issuance basis and an annual basis that the number of creditable emission reductions collected by the District equals or exceeds the amount of creditable emission reductions that would otherwise be required as offsets under a federal non-attainment NSR program meeting the applicable requirements of 40 CFR 51.165 and the CAA.

7.1 Definitions

7.1.1 Carryover Balance (COB): the number of CAER for each pollutant that are available in the tracking system at the end of a reporting period. The COB for a new reporting year shall consist of the running balance on the last day of the reporting period, plus any AER collected by the District and not used to satisfy the FOQ for an issued ATC, plus, for any ATC that is cancelled or not implemented by the ATC expiration date, the CAER value previously transferred from the running balance to satisfy FOQ equivalency requirements.

7.1.2 Creditable Actual Emissions Reduction (CAER): the surplus-at-time-of-use portion of an AER, and consistent with the requirements of Section 4.8.1.5. The creditability of a given emission reduction may be subject to EPA review.

7.1.3 Running Balance: the face-value, day-to-day balance of available emission reductions in the tracking system, accounting for any transfers out to an individual ATC project. The running balance at the start of each reporting period shall be the adjusted COB from the previous reporting period. The running balance may be used to satisfy the FOQ requirements from ATC projects in current or future tracking years to the extent the CAER balance is surplus-adjusted-at-the-time-of-use when withdrawn.

7.1.4 Surplus-at-time-of-use: an adjustment made to the value, in tons per year, of an AER, ERC, or IER by applying the definition of surplus (as defined in Section 3.2.1) as of the date of issuance of the ATC project.

7.1.5 Tracking system: the accounting system used for recording all parameters required by this Federal Offset Equivalency Demonstration.

7.1.6 Tracking year: the reporting period from August 20 of one year to August 19 of the following year.

7.2 Only the CAER portion of following types of emission reductions may be used to demonstrate offset equivalency:

7.2.1 Emission Reduction Credits; or

7.2.2 Air Quality Improvement Deductions (as defined in Section 3.6) resulting from original ERC banking actions finalized after August 20, 2001; or

7.2.3 Other Actual Emissions Reductions (AER, as defined in Section 3.2) resulting from a permitting action that has not been banked or previously used as an offset in this demonstration; or

7.2.4 Any reduction in actual emissions (after August 20, 2001) that results from the application of BACT to a non-major source or a project that does not result in a federal major modification.

7.3 Offset Tracking System

7.3.1 The APCO may add or remove a CAER or a portion of a CAER, from the tracking system subject to review by the EPA.

7.3.2 The APCO shall implement a tracking system for each of the parameters listed below:

7.3.2.1 Federal Offset Quantity (FOQ) in tons per year and associated ATC project number, including the ATC issuance date and whether the ATC was implemented, pending or cancelled as of August 19th of each year.

7.3.2.2 District Offset Quantity (DOQ) in tons per year and associated ATC project number, including the ATC issuance date and whether the ATC was implemented, pending or cancelled as of August 19th of each year.

7.3.2.3 For each CAER in tons per year collected by the District, the type of CAER (for example, ERC, AQID, or AER), the associated ATC project number(s), if applicable, and the project number identifying the original banking action or emission reduction project that created the CAER.

7.3.2.4 The running balance in tons per year including all additions and subtractions of any CAER in the tracking system. The APCO shall track every addition and subtraction of a CAER using the parameters tracked in Sections 7.4.1, 7.4.2, and 7.4.3.

7.4 Programmatic Permit-Level Federal Offset Equivalency Demonstration for PM10, PM2.5, and SOx

7.4.1 For each project that will result in a new major source or federal major modification, the APCO shall include in its ATC application review document, the following determinations. Such information shall be made available in accordance with the notification procedures specified in Section 5.0. The District shall also make available to the public, the ARB and the EPA any additional data pertinent to the determinations.

7.4.2 The application review document for every ATC project shall include:

7.4.2.1 A determination of the FOQ.

7.4.2.2 A determination of the DOQ, if any.

7.4.2.3 For each CAER (from an ERC or IER) submitted by the ATC applicant, the APCO shall determine the surplus-at-time-of-use quantity.

7.4.2.4 Demonstration of federal offset equivalency.

7.4.2.4.1 If the quantity determined in Section 7.4.2.3 is equal to or greater than the FOQ, then offset equivalency has been demonstrated for the ATC project/permit, subject to EPA review. Any remaining CAER amount greater than the FOQ shall be tracked, and shall be credited to the COB at the time of annual report review if the ATC project has been implemented. If necessary, the APCO may add the CAER to the running balance when the ATC project has been implemented.

7.4.2.4.2 If the quantity determined in Section 7.4.2.3 is less than the FOQ, the APCO shall identify and reserve from the tracking system running balance, the necessary quantity of face-value offsets to provide the amount of CAER necessary to demonstrate offset equivalency for the ATC project. The APCO shall document the surplus-at-time-of-use value of the face-value offsets reserved, and shall include the demonstration in the application review document.

7.4.2.4.2.1 If the quantity determined in Section 7.4.2.3 plus the amount of additional CAER from the tracking system is equal to the FOQ, equivalency will have been demonstrated for the ATC project/permit, subject to EPA review.

7.4.2.4.2.2 If offset equivalency cannot be demonstrated, then the ATC project will not have met federal offset equivalency requirements. The APCO shall deny the application for the project until federal offset equivalency can be demonstrated in accordance with this section.

7.4.3 Upon issuance of the ATC permit, the APCO shall transfer the reserved CAER used to offset the ATC's FOQ obligation out of the running balance. If the ATC permit is cancelled or expires, then the APCO may reinstate the specific CAER transferred out for that ATC permit at the time of annual report review. If necessary, the APCO may return the CAER to the running balance when the ATC is cancelled or expires.

7.5 Annual Reporting Schedule

7.5.1 The report shall include all tracked parameters, as specified in Section 7.3.2, which occur between August 20 to August 19 of each year, based on ATC issuance or other final action date.

7.5.2 For each tracking year, the APCO shall submit a final report to the ARB and the EPA no later than November 20 of each year. In addition, the APCO shall present the report to the District Governing Board and release it to the public, each year, at the first Board meeting following its submittal to the EPA.

7.5.3 The report shall include the following information for each pollutant included in the equivalency demonstration:

7.5.3.1 The number of ATC projects, if any, issued that were either a new major sources or federal major modifications.

7.5.3.2 A list of ATC projects, if any, issued that were either a new major source or federal major modification. For each ATC project, the project number, the pollutant(s) for which the project was either a new major source or federal major modification, the FOQ, the DOQ, if applicable, the number of CAERs submitted by the ATC applicant, and the number, if any, of additional CAER withdrawn from the tracking system running balance to demonstrate equivalency, if applicable.

7.5.3.3 The COB at the end of the tracking period for each pollutant, including:

7.5.3.3.1 The COB for each pollutant from the beginning of the current tracking period.

7.5.3.3.2 A line-item list of each addition and subtraction to the running balance during the tracking period, including the tracked parameters for each addition/subtraction.

7.6 All documents created and/or used in implementing the requirements of Section 7.0 shall be kept and maintained by the APCO for no less than five years from the date of their creation and/or use, whichever is later.

8.0 Pre-Baseline ERC Tracking System and Usage Caps from District Attainment Plans

8.1 For all new and modified sources in the District subject to the requirements of this rule, the APCO shall track the quantity of pre-baseline ERCs for federal non-attainment pollutants and their precursors used as offsets.

8.2 ERCs that were banked prior to the baseline year for a given District-adopted and EPA-approved Attainment Plan shall not be used to offset emissions increases under the provisions of this rule if the usage of such credits during the effective period of the plan exceeds the respective pollutant's Pre-Baseline ERC Usage Cap in the plan.

8.3 Such caps on pre-baseline ERC usage remain in effect until the end of the plan's effective period, or until such time as EPA approves revised caps through an Attainment Plan revision process or a Rate of Progress update.

9.0 Application Shield for Routine Replacement Emissions Units and Temporary Replacement Emissions Units (TREUs)

9.1 For a Routine Replacement Emissions Unit or a TREU, for which an Authority to Construct is required, the permitted source may continue to operate under an application shield, provided that all of the following conditions are met.

9.1.1 An application for the Routine Replacement Emissions Unit or TREU has been submitted within seven calendar days of completing the construction or installation of the replacement.

9.1.2 The source operates in compliance with all applicable requirements of the federal, state, and District rules and regulations.

9.1.3 For a TREU, all of the following conditions must be met:

9.1.3.1 The TREU results in no increase in design capacity, unless a replacement unit of the same or lower design capacity is not available, in which case the replacement can result in a design capacity increase of up to 10%.

9.1.3.2 The TREU results in no change to the permitted throughput or emission limits due to a change in the design capacity as part of the replacement.

9.1.3.3 The TREU performs the same function as the equipment being replaced.

9.1.3.4 The TREU either is addressed by a BARCT rule or uses technology with a minimum control efficiency of at least 85%.

9.2 When the application has been deemed complete by the APCO, the application shield shall be made effective retroactive from the date of application submittal until the application is either approved or denied.

9.2.1 The application shield is not applicable if the District's final action is delayed due to the failure of the applicant to submit timely information requested by the District. The source must also submit additional information for any requirements that become applicable after a complete application is submitted, but before a PTO is issued.

9.3 The application shield does not exempt the operator from any applicable requirements.

9.4 The application shield applies only to applications for Routine Replacement Emissions Units, and TREUs meeting the requirements of 9.1.3.1 through 9.1.3.4, and does not authorize any increases to the permitted throughput or emissions due to a change in design capacity as part of a Routine Replacement Emissions Unit or a TREU.

9.5 For replacements at major sources, the application shield applies only to Routine Replacement Emissions Units that result in no significant emissions increase according to the applicability calculations of 40 CFR 51.165(a)(2)(ii)(C), "Actual-to-projected actual applicability test for projects that only involve existing emissions units". For the purposes of this section, a Routine Replacement Emissions Unit is an

existing emissions unit. A copy of the emission calculations used to determine that the Routine Replacement Emissions Unit did not result in a significant emissions increase must be included with the application required by Section 9.1.1.

9.6 For a TREU that is removed from the Stationary Source within seven calendar days of completing the installation of the TREU, the application requirements of Section 9.1.1 shall not apply, provided the permittee submits, within seven calendar days of completing the installation of the TREU, a report to the District demonstrating compliance with the requirements of Section 9.

10.0 All references and citations in this rule to the Title 40 of the Code of Federal Regulations (CFR) and the California Health & Safety Code (CH&SC) refer to the references as in effect on the date of adoption of this rule.

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Exhibit 4

District Rule 2010

RULE 2010 PERMITS REQUIRED (Adopted May 21, 1992, Amended December 17, 1992)

1.0 Purpose

The purpose of this rule is to require any person constructing, altering, replacing or operating any source operation which emits, may emit, or may reduce emissions to obtain an Authority to Construct or a Permit to Operate. This rule also explains the posting requirements for a Permit to Operate and the illegality of a person willfully altering, defacing, forging, counterfeiting or falsifying any Permit to Operate.

2.0 Applicability

The provisions of this rule shall apply to any person who plans to or does operate, construct, alter, or replace any source operation which may emit air contaminants or may reduce the emission of air contaminants.

3.0 Authority to Construct

Any person building, altering or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants or the use of which may eliminate or reduce or control the issuance of air contaminants, shall first obtain authorization for such construction from the APCO. An Authority to Construct shall remain in effect until the Permit to Operate the source operation for which the application was filed is granted or denied, or the application is canceled as described in Rule 2050 (Cancellation of Application).

4.0 Permit to Operate

Before any new or modified source operation described in Section 3.0, or any existing source operation so described may be operated, a written permit shall be obtained from the APCO. No Permit to Operate shall be granted either by the APCO or the Hearing Board for any source operation described in Section 3.0 constructed or installed without authorization as required by Section 3.0 until the information required is presented to the APCO and such source operation is altered, if necessary, and made to conform to the standards set forth in Rule 2070 (Standards for Granting Applications) and elsewhere in these rules and regulations.

4.1 New Equipment

A person shall notify the APCO before operating or using any source operation granted an Authority to Construct. Upon such notification, the Authority to Construct shall serve as a temporary Permit to Operate for the source operation until the Permit to Operate is granted or denied. The source operation shall not be operated contrary to the conditions specified in the Authority to Construct.

4.2 Modified Equipment

The Authority to Construct granted to modify any source operation having a valid Permit to Operate shall serve as a temporary Permit to Operate for the source operation until a new Permit to Operate is granted or denied. The modified source operation shall not be operated contrary to the conditions specified in the Authority to Construct. A person shall notify the APCO in writing when construction is completed.

4.3 Existing Equipment

When an application for a Permit to Operate is filed for any existing source operation, the application shall serve as a temporary Permit to Operate for the source operation. If the source operation was previously operated under a Permit to Operate and has not been altered, it shall not be operated under a temporary Permit to Operate contrary to the conditions specified in the previous Permit to Operate.

5.0 Posting of a Permit to Operate

A person who has been granted a Permit to Operate any source operation described in Section 4.0 shall firmly affix such Permit to Operate, an approved facsimile, or other approved identification bearing the permit number upon the source operation, in such a manner as to be clearly visible and accessible. In the event that the source operation is so constructed or operated that the Permit to Operate cannot be so placed, the Permit to Operate shall be mounted so as to be clearly visible in an accessible place within 25 feet of the source operation or maintained readily available at all times on the operating premises.

6.0 Altering of Permit

A person shall not willfully deface, alter, forge, counterfeit, or falsify a Permit to Operate any source.

Exhibit 5

District Rule 2520

RULE 2520 FEDERALLY MANDATED OPERATING PERMITS (Adopted June 15, 1995; Amended June 21, 2001; Amended August 15, 2019; Amended June 20, 2024)

1.0 Purpose

The purpose of this rule is to provide for the following:

1.1 An administrative mechanism for issuing operating permits for new and modified sources of air contaminants in accordance with requirements of 40 CFR Part 70.

1.2 An administrative mechanism for issuing renewed operating permits for sources of air contaminants in accordance with requirements of 40 CFR Part 70.

1.3 An administrative mechanism for revising, reopening, revoking, and terminating operating permits for sources of air contaminants in accordance with requirements of 40 CFR Part 70.

1.4 An administrative mechanism for incorporating requirements authorized by preconstruction permits issued under District Rule 2201 (New and Modified Stationary Source Review) in a Part 70 permit as administrative amendments, provided that such permits meet procedural requirements substantially equivalent to the requirements of 40 CFR 70.7 and 70.8, and compliance requirements substantially equivalent to those contained in 40 CFR 70.6.

1.5 The applicable federal and local requirements to appear on a single permit.

2.0 Applicability

The provisions of this rule shall apply to the following sources:

2.1 Major air toxics sources,

2.2 Any stationary source that emits or has the potential to emit 100 tons per year of any air contaminant,

2.3 Any major source,

2.4 Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA published after July 21, 1992 except as provided for in section 4.2 of this rule.

2.4.1 For stationary sources, which are subject to Rule 2520 solely as a result of Section 2.4, only the emissions units within the stationary source that are subject to the section 111 or 112 standard or requirement shall be subject to the Part 70 permitting requirements;

2.5 A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV of the CAA;

2.6 Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act;

2.7 A solid waste incinerator subject to a performance standard promulgated pursuant to section 111 or 129 of the CAA; and

2.8 Any source in a source category designated, pursuant to 40 CFR Part 70.3, by rule of the EPA.

2.9 When calculating the potential to emit for the purpose of determining if the requirements of this rule are applicable, fugitive emissions must only be included for determining non-hazardous air pollutant emissions if the source is included in the list of source categories identified in the major source definition in 40 CFR part 70.2, or when determining if a stationary source is a major air toxics source.

3.0 Definitions

3.1 Acid Rain Unit: an acid rain unit is any fossil fuel-fired combustion device that is an affected unit under 40 CFR Part 72.6 and therefore subject to the requirements of Title IV (Acid Deposition Control) of the CAA.

3.2 Administrative Permit Amendments: Administrative amendment is a permit amendment that:

3.2.1 Corrects typographical errors;

3.2.2 Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;

3.2.3 Requires more frequent monitoring or reporting by the permittee; or

3.2.4 Allows for a change in ownership or operational control of a source where the District determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the District; and

3.2.5 Incorporates other applicable requirements which the EPA has determined as part of an approved part 70 program to be similar to those in Sections 3.2.1 through 3.2.4.

3.2.6 Incorporates requirements from an Authority to Construct for a new or modified emissions unit pursuant to the provisions of District Rule 2201 (New and Modified Stationary Source Review) provided that a certificate of conformity with procedural requirements of 40 CFR part 70 has been issued in conjunction with the Authority to Construct.

3.3 Affected Source: a source that contains one or more affected units.

3.4 Affected Unit: an emissions unit subject to a requirement or limitation of Title IV of the Federal Clean Air Act.

3.5 Affected States: states that are within 50 miles of a permitted source, or states contiguous to California whose air quality may be affected by a Part 70 permitting action, renewal, or modification.

3.6 Applicable Requirements: any of the federally enforceable requirements listed in the definition of applicable requirements in 40 CFR part 70.2.

3.7 Certificate of Conformity: a written document issued by the District certifying that an Authority to Construct for the new or modified source issued under District Rule 2201 (New and Modified Stationary Source Review) has been issued in accordance with procedural requirements substantially equivalent to the requirements of 40 CFR 70.7 and 70.8, and compliance requirements substantially equivalent to those contained in 40 CFR 70.6(c).

3.8 Clean Air Act (CAA): refers to the Federal Clean Air Act as amended in 1990 (42 U.S.C. Section 7401 et seq.).

3.9 Designated representative: a responsible person or official authorized by the owner or operator of a unit at an affected source to represent the owner or operator in manners pertaining to emission allowances, permitting, and compliance plans.

3.10 District's Effective Date of Major Source Permitting Program: date of approval by EPA of the District's Title V operating permits program.

3.11 Emissions Unit: any part or activity of a stationary source which emits, may emit, or results in the emissions of any regulated pollutant or hazardous air pollutant.

3.12 Federal Major Modification: same as that defined in District Rule 2201 (New and Modified Stationary Source Review).

3.13 Federally Enforceable: enforceable by the EPA or the public.

3.14 Final Permit: a permit that has completed all review requirements of Section 11 of this rule.

3.15 Fugitive Emissions: emissions that could not reasonably pass through a vent, chimney, stack, or other functionally equivalent opening.

3.16 General Permit: a Part 70 permit issued to sources qualifying for a model general permit. Permits issued under general permit provisions shall be subject to the same requirements of any Part 70 permit relating to renewal, revision, and permit term and content.

3.17 Hazardous Air Pollutant: pollutants listed pursuant to section 112(b) of the Federal Clean Air Act.

3.18 Initial Permits: the first permits issued to sources in accordance with the requirements of this rule for emissions units that were in existence and not exempted from the requirements of this rule on the District's effective date of major source permitting.

3.19 Major Air Toxics Source: a stationary source that emits or has the potential to emit, including fugitive emissions, 10 tons per year or more of a hazardous air pollutant, or 25 tons per year or more, including fugitive emissions, of a combination of hazardous air pollutants or such lesser quantity as the EPA may establish by rule. Emissions from any oil or gas production well, with its associated equipment, and emissions from any pipeline compressor station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major air toxic sources.

3.20 Major Source: same as that defined in District Rule 2201 (New and Modified Stationary Source); except that the reference to a threshold in tons per year of nitrogen oxides shall not apply with respect to any source for which the EPA Administrator has made a finding, under section 182(f)(1) or (2) of the CAA, that requirements under section 182(f) of the CAA do not apply.

3.21 Minor Permit Modifications: are permit modifications that:

3.21.1 Do not violate requirements of any applicable federally enforceable local or federal regulations;

3.21.2 Do not relax monitoring, reporting, or recordkeeping requirements in the permit and are not significant changes in existing monitoring permit terms or conditions;

3.21.3 Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

3.21.4 Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source

has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

3.21.4.1 A federally enforceable emission cap assumed to avoid classification as a modification under any provisions of title I of the Federal Clean Air Act, prevention of significant deterioration (PSD) provisions of the CAA, or EPA PSD regulations; and

3.21.4.2 An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Federal Clean Air Act; and

3.21.5 Are not Federal Major Modifications as defined in this rule, modifications as defined in section 111 or 112 of the Federal Clean Air Act, or major modifications under the prevention of significant deterioration (PSD) provisions of Title I of the CAA or under EPA PSD regulations; and

3.21.6 Do not seek to consolidate overlapping applicable requirements.

3.22 Model General Permit: a model permit issued by the District after notice and opportunity for public participation provided under sections 11.1.4 and 11.1.5 of this rule covering numerous similar sources. Any general permit shall meet the requirements of 40 CFR 70.6(d). Any model general permit shall comply with all requirements applicable to other Part 70 permits and shall identify criteria by which sources may qualify for the general permit. A model general permit shall specify the necessary application content for sources applying for the general permit. General permits shall not be authorized for affected sources under the acid rain program unless otherwise provided in regulations promulgated by EPA under Title IV of the CAA.

3.23 Model General Permit Template: a list of conditions issued by the District after notice and opportunity for public participation provided under section 11.1.4 and 11.1.5 of this rule covering numerous similar sources that address general non-source-specific requirements applicable to a source category. A model general permit template shall specify the necessary application content, including the criteria that must be met by the applicants in order to qualify for the template, for sources applying to include the general permit template in their Part 70 permit.

3.24 New Source: for the purpose of determining the applicable administrative requirements of Rule 2520, a new source is a source that commences operation after the District's effective date of the District's Part 70 permitting program.

3.25 Part 70 Permit: an operating permit that is issued pursuant to the requirements of this rule.

3.26 Permit Amendment: revision to a federally enforceable term or condition of a permit issued pursuant to the requirements of this rule.

3.27 Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including pollution control equipment and restrictions in hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is incorporated into the applicable permit as a federally enforceable permit condition, or is contained in an EPA approved State Implementation Plan (SIP). In addition, until 1/25/97 any physical or operational limitation on the capacity of the source to emit a pollutant, including pollution control equipment and restrictions in hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if such limitations are contained in a District permit, or a District SIP submittal on which EPA has not taken a final action.

3.28 Regulated Air Pollutant: A "regulated air pollutant" is any pollutant: 1) which is emitted into or otherwise enters the ambient air, and 2) for which the EPA has adopted an emission limit, standard, or other requirement. Regulated air pollutants include:

3.28.1 Oxides of nitrogen and volatile organic compounds;

3.28.2 Any pollutant for which a national ambient air quality standard has been promulgated pursuant to section 109 of the CAA;

3.28.3 Any pollutant subject to a new source performance standard promulgated pursuant to section 111 of the CAA;

3.28.4 Any ozone-depleting substance specified as a Class I (chlorofluorocarbons) or Class II (hydrofluorocarbons) substance pursuant to Title VI of the CAA; and

3.28.5 Any pollutant subject to a standard or requirement promulgated pursuant to section 112 of the CAA, including:

3.28.5.1 Any pollutant listed pursuant to section 112(r) of the CAA (Prevention of Accidental Releases) shall be considered a "regulated air pollutant" upon promulgation of the list.

3.28.5.2 Any hazardous air pollutant subject to a standard or other requirement promulgated by the U.S. EPA pursuant to section 112(d) or adopted by the District pursuant to 112(j) of the CAA shall be considered a "regulated air pollutant" for all sources or categories of sources: 1) upon promulgation of the standard or requirement, or 2) 18 months after the standard or requirement was scheduled to be promulgated pursuant to section 112(e)(3) of the CAA, whichever is earlier.

3.28.5.3 Any hazardous air pollutant subject to a District case-by-case emissions limitation determination for a new or modified source, prior to the EPA promulgation or scheduled promulgation of an emissions limitation shall be considered a "regulated air pollutant" when the determination is made pursuant to section 112(g)(2) of the CAA. In case-by-case emissions limitation determinations made pursuant to section 112(g) of the CAA, the hazardous air pollutant shall be considered a "regulated air pollutant" only for the individual source for which the emissions limitation determination was made.

3.29 Responsible Official: is one of the following:

3.29.1 For a corporation, the responsible official shall be a president, secretary, treasurer, or vice president in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation. The responsible official may be a duly authorized representative rather than any of the above if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit; and

3.29.1.1 the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million in 1980 dollars; or

3.29.1.2 the District has approved a petition from the original responsible person to delegate authority.

3.29.2 For a public agency the responsible official shall be either the principal executive officer or the ranking elected official. The principal executive officer, in the case of a federal agency, may be the executive officer having responsibility for a geographical unit.

3.29.3 For a partnership or sole proprietorship, the responsible official is a general partner or the proprietor, respectively.

3.30 Significant Permit Modification: Permit amendments that do not qualify as minor permit modifications or as administrative amendments.

3.31 Stationary Source: same as that defined in District Rule 2201 (New and Modified Stationary Source Review)

4.0 Sources Exempt from Rule 2520

The following sources are exempt from obligation to obtain a Part 70 permit subject to the provisions of this rule or 40 CFR part 70:

4.1 Any source listed in section 2.0 of this rule that is not: 1) a major source; 2) a major air toxics source; 3) a stationary source with the potential to emit of 100 tons per year of any air contaminant, 4) affected source; 5) a source that EPA determines is required to obtain a Part 70 permit upon promulgation of a standard issued pursuant to section 111 or 112 of the CAA; or 6) a solid waste incineration unit required to obtain a Part 70 permit pursuant to section 129(e) of the CAA;

4.2 Non-major sources subject to a standard or other requirement under either section 111 (NSPS) or section 112 (HAPs) of the CAA after July 21, 1992 publication, if the EPA, at the time the new standard is promulgated, determines that such sources are deferred or exempt from the requirements to obtain a Part 70 permit under the provisions of this rule;

4.3 All sources and source categories that would be required to obtain a Part 70 permit solely because they are subject to 40 CFR part 60, Subpart AAA - Standards of Performance for New Residential Wood Heaters;

4.4 All sources and source categories that would be required to obtain a Part 70 permit solely because they are subject to 40 CFR part 61, Subpart M - National Emission Standard for Hazardous Air Pollutants for Asbestos, section 61.145, Standard for Demolition and Renovation; and

4.5 Permitting actions that do not involve a change to the federally enforceable terms or conditions of a Part 70 permit. The requirements of other applicable rules, such as Rule 2201 (New and Modified Stationary Source Review), apply to these permitting actions.

4.6 All sources exempted from the requirements of 40 CFR part 70 by District Rule 2530 (Federally Enforceable Potential to Emit) as approved by the EPA into the state implementation plan.

5.0 Requirements for Filing Timely Applications

The owner or operator of any source subject to the requirements of this rule shall file timely and complete applications in accordance with the following requirements:

5.1 Initial Permits

5.1.1 For sources subject to the requirements of this rule, and in existence prior to effective date of the District's Part 70 permitting program, no later than 12 months after the effective date of the District's Part 70 permitting program. To allow for an orderly transition, the District may establish an earlier application deadline for various sources or source categories. In no event shall applications be required prior to the effective date of the District's Part 70 permitting program.

5.1.2 For a source that becomes subject to the requirements of this rule, including a sources previously exempt from the requirements of Rule 2520 pursuant to section 5.2 of Rule 2530, no later than 12 months after the source becomes subject to the requirements of this rule. To allow for an orderly transition, the District may establish an earlier application deadline for various sources or source categories. The District may also receive applications for the purpose of determining applicability of the requirement to obtain a Part 70 permit.

5.2 Permit Renewals

The holder of a Permit to Operate issued subject to the provisions of this rule shall submit to the District an application for renewal at least six months, but not greater than 18 months, prior to the permit expiration date. Permits to operate for all emissions units at a stationary source shall undergo simultaneous renewal.

5.3 New and Modified Sources Subject to the Requirements of this Rule

5.3.1 New Sources

New Sources, or sources subject to section 5.2 of Rule 2530 shall submit an application for Permit to Operate that complies with the requirements of this rule within 12 months of commencing operations.

5.3.2 Minor or Significant Permit Modifications

Except when allowed by the operational flexibility provisions of section 6.4 of this rule, the permittee shall file an application for a permit modification prior to implementing the requested change. This also applies to sources not previously subject to the requirements of this rule that become subject to the requirements due to a minor or significant modification. Applications for permit amendments to conditions or limitations required under title IV (acid rain) must meet the requirements of 40 CFR part 72 of the Federal Clean Air Act and all applicable District rules.

5.3.3 A source applying for an Authority to Construct for a new or modified emissions unit pursuant to the provisions of District Rule 2201 (New and Modified Stationary Source Review) may apply simultaneously for a Part 70 permit, or a certificate of conformity in accordance with the deadlines specified in subsections 5.3.1 or 5.3.2 of this rule.

5.3.4 Administrative Permit Amendments

Except when allowed by the operational flexibility provisions of section 6.4 of this rule, the permittee shall file an application for administrative permit amendments prior to implementing the requested change.

6.0 Source's Ability to Make Changes

Except as provided by the application shield provisions of section 13.1 of this rule, or by the operational flexibility provisions of section 6.4 of this rule, a source's ability to implement changes shall be limited to the following:

6.1 Administrative Permit Amendments

The source may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request. Should the District or EPA ultimately reject the source's proposed amendments, the source shall be subject to enforcement proceedings for violation of any existing permit terms and conditions.

6.2 Minor Permit Modifications

The source may implement the changes addressed in the request for a minor permit modification immediately upon submittal of the request, provided that the modification has been authorized by an Authority to Construct if required by District Rule 2010. If the source implements the changes before its part 70 permit is amended, the source need not comply with the existing part 70 permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions, the existing permit terms and conditions it seeks to modify may be enforced against it. Should the District or EPA ultimately reject the source's proposed amendments, the source shall be subject to enforcement proceedings for violation of any existing permit terms and conditions.

6.3 Significant Permit Amendments

The source may implement the changes addressed in the request for a significant permit modification only after a final Part 70 permit amendment is issued by the District.

6.4 Operational Flexibility

The APCO shall allow specified changes in operations at a source without requiring a permit amendment. The source may gain operational flexibility through the use of the following options:

6.4.1 Contravening an Express Permit Term

The permittee may implement certain changes that contravene an express condition without triggering the requirements of this rule for permit modifications, if the following conditions are met:

6.4.1.1 At least 7 days prior to implementation of the proposed change the District and the EPA are notified in a written notice which includes a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change;

6.4.1.2 The District does not object in writing to the proposed change within the 7 day review period;

6.4.1.3 The proposed change is not a Federal Major Modification, or a modification under section 111 or 112 of the CAA, or a major modification under the prevention of significant deterioration (PSD) provisions of Title I of the CAA or EPA PSD regulations;

6.4.1.4 The change will not violate any applicable federal requirement;

6.4.1.5 The change will not contravene federally enforceable conditions for monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements; and

6.4.1.6 The proposed change will not result in emissions in excess of those allowed by the permit, including a work place standard or a federally enforceable emissions cap.

6.4.2 Alternative Operating Scenarios

The Part 70 permit may include alternative operating scenarios provided that:

6.4.2.1 Each alternative operating scenario is identified in the permit application;

6.4.2.2 The terms and conditions are approved in writing by the APCO;

6.4.2.3 The terms and conditions are incorporated into the permit; and

6.4.2.4 The terms and conditions are in compliance with all applicable District, state, and federal requirements.

6.4.2.5 Changes between operating scenarios must be recorded in a contemporaneous log.

6.4.3 Voluntary Emission Caps

The APCO shall issue a Part 70 permit that contains terms and conditions that allow for trading of emissions increases and decreases within the stationary source solely for the purpose of complying with a voluntary emissions cap established in the permit independent of otherwise applicable federal requirements provided that:

6.4.3.1 The requirements of subsections 6.4.2.1, 6.4.2.3, and 6.4.2.4 are met;

6.4.3.2 The terms and conditions are approved in writing by the APCO as quantifiable and enforceable;

6.4.3.3 The terms and conditions are consistent with the applicable Authority to Construct: and

6.4.3.4 At least 7 days prior to implementation of the proposed change the District and the EPA are notified in a written notice which includes when the change will occur, a brief description of the change in emissions that will occur, and how these increases and decreases in emissions will comply with the terms and conditions of the permit.

6.4.4 Other Changes Not Requiring Permit Amendment

A permittee may implement changes, including the addition of new emission units, without triggering the permit modification or amendment requirements of this rule until the time of permit renewal, provided:

6.4.4.1 The changes meet all applicable District, state, and federal requirements;

6.4.4.2 Contemporaneous with implementation of the change, the District and the EPA are notified in a written notice which includes a brief description of the change, the date the change occurred, any change in emissions, the pollutants emitted, and any new applicable requirement as a result of the change;

6.4.4.3 The owner or operator of the source maintains records of the resulting emissions changes;

6.4.4.4 The changes are neither addressed nor prohibited in any existing permit term or condition;

6.4.4.5 The changes, either by themselves or in combination with all other changes that have occurred without permit amendment under the requirements of this rule since the most recent renewal, do not constitute a Federal Major Modification or a major modification under the prevention of significant deterioration (PSD) provisions of Title I of the CAA; or

6.4.4.6 The changes do not constitute a modification as defined in Section 111 (NSPS) or section 112 (Hazardous Air Pollutants) of the Federal Clean Air Act; and

6.4.4.7 The change does not violate any terms or conditions of the existing permit.

6.4.5 Temporary Sources

The District may issue a single permit authorizing emissions from similar operations by the same source owner or operator at more than one location provided:

6.4.5.1 The source is not subject to the provisions of Title IV of the CAA;

6.4.5.2 The permit contains conditions that assure compliance with all applicable requirements at each location; and

6.4.5.3 The permit includes a requirement that the operator notifies the District in writing at least 10 days prior to changing locations.

6.4.5.4 The operation is temporary and involve at least one change of location during the term of the permit.

7.0 Application Content

7.1 Permit Applications

To be deemed complete, a Part 70 permit application must contain the following:

7.1.1 Identifying information, including company name and address (or plant name and address if different from the company name and address), owner's name and agent, and telephone number and names of plant site contact person.

7.1.2 A description of the source's processes and products (by Standard Industrial Classification Code), including any associated with each alternate scenario(s) proposed by the applicant.

7.1.3 The following emission-related information:

7.1.3.1 All emissions of pollutants, including fugitive emissions, for which the source is major, and all emissions of regulated air pollutants, including fugitive emissions, for which the source is subject to an underlying applicable requirement. A permit application shall describe all emissions of regulated air pollutants emitted from any permitted emissions unit, and list the exempt categories from Rule 2020 which describe any insignificant equipment located at the facility. Applicant may submit quantification of actual emissions, except when potential emissions are needed to demonstrate compliance with an applicable requirement. As a demonstration of actual emissions, a source may submit the most recent emissions statement under Rule 1160, Emissions Statement, or emissions inventory report under Health and Safety Code 44300, to the extent that the statement addresses all regulated pollutants.

7.1.3.2 Information related to emissions of air pollutants needed by the District to verify which requirements are applicable to the source, and other information necessary to determine and collect the fees as prescribed in Regulation III of the District rules and regulations.

7.1.3.3 Identification and description of all points of emissions described in section 7.1.3.1 of this rule in sufficient detail to establish the basis for fees and applicable requirements.

7.1.3.4 Emissions rate in tons per year and in such terms as are necessary to establish compliance consistent with the applicable standard reference test method.

7.1.3.5 The following information to the extent it is needed to determine or regulate emissions: fuels, fuel use, raw materials, process weight rate, production rates, and operating schedules.

7.1.3.6 Identification and description of air pollution control equipment and compliance monitoring devices or activities.

7.1.3.7 Limitations on source operation affecting emissions or any work practice standards, where applicable, for all regulated pollutants.

7.1.3.8 Other information required pursuant to any applicable requirement (including information related to stack height limitations developed pursuant to section 123 of the CAA).

7.1.3.9 Calculations on which the information in sections 7.1.3.1 through 7.1.3.8 of this rule is based.

7.1.4 The following air pollution control requirements:

7.1.4.1 Citation and description of all applicable requirements, and

7.1.4.2 Description of or reference to any applicable test method for determining compliance with each applicable requirement.

7.1.4.3 In addition to identifying all applicable requirements, an applicant may propose consolidation of overlapping requirements. The applicant shall provide information that demonstrates that the proposed consolidation of requirements, as a whole, is at least as stringent as, and assures compliance with, each individual requirement.

7.1.5 Other specific information that may be necessary to implement and enforce other applicable requirements of the CAA or of 40 CFR Part 70 or to determine the applicability of such requirements.

7.1.6 An explanation of any proposed exemptions from otherwise applicable requirements.

7.1.7 The applicant may submit copies of valid Permits to Operate issued by the District, to the extent that the information required under sections 7.1.1 through 7.1.6 is contained in those permits.

7.1.8 Additional information as determined to be necessary by the District to define alternative operating scenarios proposed by the source or to define other permit terms and conditions implementing the operational flexibility provisions of section 6.4 of this rule.

7.1.9 A compliance plan that contains all the following:

7.1.9.1 A description of the compliance status of the source with respect to all applicable requirements.

7.1.9.2 For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements.

7.1.9.3 For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis.

7.1.9.4 For requirements for which the source is not in compliance at the time of permit issuance, a narrative description of how the source will achieve compliance with such requirements.

7.1.9.5 A compliance schedule as follows:

7.1.9.5.1 For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis. A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term shall satisfy this provision, unless a more detailed schedule is expressly required by the applicable requirement.

7.1.9.5.2 A schedule of compliance for a source that will not be in compliance with all applicable requirements at the time of permit issuance. Such a schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will not be in compliance at the time of permit issuance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree, Hearing Board order or administrative order to which the source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.

7.1.9.6 For sources required to have a schedule of compliance to remedy a violation, a schedule for submission of certified progress reports no less frequently than every 6 months.

7.1.9.7 The compliance plan content requirements specified in this section shall apply and be included in the acid rain portion of a compliance plan for an affected source, except as specifically superseded by regulations promulgated under title IV of the CAA with regard to the schedule and method(s) the source will used to achieve compliance with the acid rain emissions limitations.

7.1.10 Requirements for compliance certification, including the following:

7.1.10.1 A certification of compliance with all applicable requirements by a responsible official consistent with requirements of section 10.0 of this rule and section 114(a)(3) of the CAA;

7.1.10.2 A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods;

7.1.10.3 A schedule for submission of compliance certifications during the permit term, to be submitted no less frequently than annually, or more frequently if specified by the underlying applicable requirement or by the District; and

7.1.10.4 A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements of the CAA, which includes 40 CFR part 64 requirements under section 114(a)(3) of the CAA.

7.1.11 The use of nationally-standardized forms for acid rain portions of permit applications and compliance plans, as required by regulations promulgated under title IV of the Act.

7.1.12 Corrected information shall be provided to the District when the responsible official becomes aware that incorrect or incomplete information has been submitted.

7.1.13 Demonstration of applicability of the most stringent applicable requirement amongst multiple options can be made by a simple declaration of applicability by the applicant.

7.2 General Permit

The District may, in a model general permit, provide for permit applications that deviate from the application content requirements of section 7.1, provided that such applications meet the requirements of Title V of the CAA, and include all information necessary to determine qualification for, and to assure compliance with, the model general permit.

7.3 General Permit Template

The District may, in a model general permit template, provide for permit applications that deviate from the application content requirements of section 7.1, provided that such applications meet the requirements of Title V of the CAA, and include all information necessary to determine qualification for, and to assure compliance with, the model general permit template. For applicable requirements not covered by the

general permit template, an application shall include information required pursuant to section 7.1 of this rule.

8.0 Duration of a Permit to Operate

8.1 Each Permit to Operate, including model general permits and model general permit templates, shall be valid for up to five years, or twelve years for solid waste incineration units combusting municipal waste under section 129(e) of the Federal Clean Air Act unless revoked or suspended by the Air Pollution Control Officer, the EPA, or the District's Hearing Board. Any permit for solid waste incineration units combusting municipal waste under section 129(e) of the Federal Clean Air Act that has a permit term of more than 5 years shall be subject to review, including public notice and comment in accordance with section 11.3 of this rule, at least once every 5 years. The District shall also revoke, suspend, or modify a model general permit or a model general permit template when the sources described in the model permit become subject to additional applicable requirements.

8.2 The permit expiration date shall be specified on the Permit to Operate.

8.3 Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with the requirements of section 5.2 of this rule. Once a timely and complete renewal application has been submitted, all terms and conditions of the permit shall remain in effect until the renewal permit has been issued or denied.

8.4 Failure to pay the annual permit fees and other applicable fees as prescribed in Regulation III of these Rules and Regulations may result in revocation or suspension of the Permit to Operate.

9.0 Permit Content

Each permit issued under this rule, including model general permits and temporary source permits, shall include the following elements:

9.1 Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance.

9.1.1 The permit shall specify and reference the origin of an authority for each term or condition, and identify any difference in form as compared to the applicable requirements upon which the term or condition is based.

9.1.2 The permit shall state that, where an applicable requirement of the CAA is more stringent than an applicable requirement or regulations promulgated under title IV of the CAA, both provisions shall be incorporated into the permit and shall be enforceable by the administrator.

9.1.3 If an applicable implementation plan allows a determination of an equivalent alternative emission limit to be made in the permit issuance, renewal, or significant modification process, any permit containing such equivalency determination shall contain provisions to ensure that any resulting emissions limit has been demonstrated to be quantifiable, accountable, enforceable, and based on replicable procedures.

9.2 The permit expiration date shall be specified on the Permit to Operate.

9.3 Monitoring Requirements

Each permit shall contain the following requirements with respect to monitoring:

9.3.1 All emissions monitoring and analysis procedures or test methods required under the applicable requirements, including any procedures and methods promulgated pursuant to sections 504(b) or 114(a)(3) of the CAA. Where standard test methods or procedures are used, a reference to the test method or procedure shall be sufficient;

9.3.2 Where applicable requirements do not require periodic testing or instrumental or non-instrumental monitoring, periodic monitoring to yield reliable data for the relevant time period that are representative of the source's compliance with the permit, as reported pursuant to the requirements of section 9.5 of this rule. Such monitoring requirements shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with applicable requirement. Recordkeeping requirements may be sufficient to meet the requirements of this section; and

9.3.3 As necessary, requirements concerning the use, maintenance, and where appropriate, installation of monitoring equipment or methods.

9.4 Recordkeeping Requirements

The permit shall incorporate all applicable recordkeeping requirements and require, where applicable, the following:

9.4.1 Records of required monitoring that include the following:

9.4.1.1 The date, place as defined in the permit, and time of sampling or measurement;

9.4.1.2 The date(s) analyses were performed;

9.4.1.3 The company or entity that performed the analysis;

9.4.1.4 The analytical techniques or methods used;

9.4.1.5 The results of such analysis; and

9.4.1.6 The operating conditions as existed at the time of sampling or measurement;

9.4.2 Retention of records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, or report. Support information includes copies of all reports required by the permit and, for continuous monitoring instrumentation, all calibration and maintenance records and all original strip-chart recordings.

9.5 Reporting Requirements

The permit shall incorporate all applicable reporting requirements and require the following:

9.5.1 Submittal of reports of any required monitoring at least every six months unless a different frequency is required by an applicable requirement. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with requirement of section 10.0 of this rule.

9.5.2 Prompt reporting of deviations from permit requirements, including those attributable to upset conditions, as defined in the permit. The report shall include the probable cause of such deviations, and any corrective actions or preventive measures taken.

9.6 A permit condition prohibiting emissions exceeding any allowances that the source lawfully holds under title IV of the CAA or the regulation promulgated thereunder.

9.6.1 No permit amendment shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit amendment under any other applicable requirement and are not considered a modification pursuant to District Rule 2201 (New and Modified Stationary Source Review).

9.6.2 No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

9.6.3 Any such allowance shall be accounted for according to the procedures established in regulations promulgated under title IV of the CAA.

9.7 A severability clause to ensure the continued validity of the various permit requirements in the event of a challenge to any portion of the permit.

9.8 Provisions stating the following:

9.8.1 The permittee must comply with all conditions of the permit. Any permit noncompliance constitutes a violation of the CAA, and the District Rules and Regulations, and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

9.8.2 That it should not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

9.8.3 The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

9.8.4 The permit does not convey any property rights of any sort, or any exclusive privilege.

9.8.5 The Permittee shall furnish to the District, within a reasonable time, any information that the District may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the District copies of records required to be kept by the permit or, for information claimed to be confidential, the permittee may furnish such records directly to EPA along with a claim of confidentiality.

9.9 Provisions to ensure payment of annual permit fees and other applicable fees as prescribed in Regulation III of these Rules and Regulations.

9.10 Terms and conditions for reasonably anticipated operating scenarios identified by the source in its application and approved by the District. Such terms and conditions:

9.10.1 Shall require the source, contemporaneous with making a change from one operating scenario to another, to record in a log at the permitted facility the scenario under which it is operating; and

9.10.2 Meet all applicable requirements and the requirements of 40 CFR Part 70.

9.11 Terms and conditions, if the permit applicant requests them, for the trading of emissions increases and decreases in the permitted facility, to the extent that any applicable requirement provides for such trading without a case-by-case approval of

each emissions trade, if the District is given 7 days advance notice. With regards to emissions reduction credits, this provision only applies to the transfer of emissions reduction credits from one entity to another. The banking or use of emission reduction credits requires case-by-case approval in accordance with District Rules 2201 and 2301. Such conditions:

9.11.1 Shall include all terms required to determine compliance with all applicable requirements; and

9.11.2 Must meet all applicable requirements and requirements of 40 CFR Part 70.

9.12 Federally-enforceable requirements

9.12.1 All terms and conditions of a permit that are required pursuant to the CAA, including provisions designed to limit potential to emit, are enforceable by the EPA and Citizens under the CAA.

9.12.2 Notwithstanding section 9.12.1 of this rule, the District shall specifically designate as not being federally enforceable under the Federal Clean Air Act any terms and conditions included in the permit that are not required under the CAA or under any of its applicable requirements. Terms and conditions so designated are not subject to the administrative requirements of this rule, but are still subject to the requirements of other District rules, when applicable.

9.13 Compliance Requirements

All permits, including model general permits and temporary source permits, shall contain the following elements with respect to compliance:

9.13.1 Compliance certification, testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. Any report or document submitted under a permit requirement or a request for information by the District or EPA shall contain a certification by a responsible official of truth, accuracy, and completeness.

9.13.2 Inspection and entry requirements that require that, upon presentation of credentials and other documents that may be required by law, the permittee shall allow an authorized representative of the District to perform the following:

9.13.2.1 Enter upon the permittee's premises where a permitted source is located or emissions related activity is conducted, or where records must be kept under condition of the permit;

9.13.2.2 Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

9.13.2.3 Inspect at reasonable times any facilities, equipment, practices, or operations regulated or required under the permit; and

9.13.2.4 Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

9.14 Compliance Schedules

9.14.1 For sources in violation of any applicable requirement, a schedule of compliance approved by the District Hearing Board in accordance with the procedure outlined in District Rule 5050 and meeting the requirements of section 7.1.9.5.2 of this rule, or as contained in applicable requirement;

9.14.2 For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements; and

9.14.3 For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis. A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term shall satisfy this provision, unless a more detailed schedule is expressly required by the applicable requirement,

9.15 For sources in violation of any applicable requirement, progress reports consistent with the applicable schedule of compliance shall be submitted at least semiannually, or at a more frequent period if required by the District Hearing Board or any other applicable requirement. Such progress report shall contain the following:

9.15.1 Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when such activities, milestones or compliance were or will be achieved; and

9.15.2 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.

9.16 Requirements for compliance certification with terms and conditions contained in the permit, including emission limitations, standards, or work practices. Permits shall include each of the following:

9.16.1 The frequency (not less than annually or such more frequent periods as specified in applicable requirements or by the District) of submission of compliance certifications;

9.16.2 A means for monitoring the compliance of the source with its emission limitations, standards, and work practices;

9.16.3 A requirement that the compliance certification include the following:

9.16.3.1 The identification of each term or condition of the permit that is the basis of the certification;

9.16.3.2 The compliance status;

9.16.3.3 Whether compliance was continuous or intermittent;

9.16.3.4 The methods used for determining the compliance status of the source, currently and over the reporting period consistent with section 9.5 of this rule; and

9.16.3.5 Such other facts as the District may require to determine the compliance status of the source.

9.16.4 A requirement that all compliance certifications be submitted to the EPA as well as to the District; and

9.16.5 Any additional requirements under sections 114(a)(3) and 504(b) of the CAA.

9.16.6 Other provisions to assure compliance with all applicable requirements, including applicable requirements with future compliance deadlines.

9.17 Part 70 permits utilizing one or more model general permit templates shall contain the terms and conditions of each template without any revisions.

9.18 Permit shield provisions indicating that compliance with the permit shall be deemed compliance with all other applicable provisions of the CAA, if the applicable requirements of such provisions are included in the permit or if the District, in acting on the permit, determines that other provisions are not applicable. A concise summary of this determination shall be included in the permit.

10.0 Certification Requirements

Any application form, report, or compliance certification submitted pursuant to these regulations shall contain certification of truth, accuracy, and completeness by a responsible official. This certification and any other certification required under this rule shall state that,

based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

11.0 Administrative Requirements

11.1 Model General Permits and Model General Permit Templates

All model general permits and model general permit templates shall be issued subject to the following procedures:

11.1.1 The APCO may issue a model general permit or model general permit template on the APCO's own initiative or in response to a petition.

11.1.2 Any person may submit a written petition to the APCO requesting the issuance of a model general permit or model general permit template for a defined class of sources. The petition shall propose a particular class of facilities, list the expected number and size of sources in the proposed class, and include a description of the processes and operating conditions of the sources within the proposed class.

11.1.3 The APCO shall provide a written response to the petition within 60 days of receipt.

11.1.4 Public Notification

11.1.4.1 The APCO shall provide a written notice of the proposed permit and, upon request, copies of the District analysis to interested parties. Interested parties shall include affected states, ARB and persons who have requested in writing to be notified. The notice shall also be given by electronic publication on the District's website and by any other means if necessary to assure adequate notice to the affected public. The public shall be given 30 days from the date of publication to submit written comments on the District's proposed action.

A copy of the District analysis and the proposed permit shall be made available at District offices for public review and comment during normal business hours and shall also be made available on the District's website. The District analysis shall include a statement that sets forth the legal and factual basis for the proposed permit conditions, including references to the applicable statutory and regulatory provisions.

The notice shall provide the following information:

11.1.4.1.1 The identification of the source categories, the activities and emissions change involved in the permitting action;

11.1.4.1.2 The name and address of the District, the name and telephone number of District staff to contact for additional information;

11.1.4.1.3 The availability, upon request, of a statement that sets forth the legal and factual basis for the proposed permit conditions;

11.1.4.1.4 The location where the public may inspect the complete application, the District analysis, the proposed permit, and all relevant supporting materials;

11.1.4.1.5 A statement that the public may submit written comments regarding the proposed decision within at least 30 days from the date of publication and a brief description of commenting procedures, and

11.1.4.1.6 A statement that members of the public may request the APCO or his designee to preside over a public hearing for the purpose of receiving oral public comment, if a hearing has not already been scheduled. The APCO shall provide notice of any public hearing scheduled to address the proposed decision at least 30 days prior to such hearing.

11.1.5 EPA Notification

The APCO shall provide written notice to the EPA of the proposed decision along with copies of the proposed permit, the District analysis, the public notice submitted for publication, and all necessary supporting information.

11.1.6 The APCO shall provide written response to persons or agencies that submitted written comments which are postmarked by the close of the public notice and comment period. All written comments and responses to such comments shall be kept on file at the District office and made available upon request.

11.1.7 For permit applications utilizing model general permit templates, public and agency comments on District's proposed actions shall be limited to the applicant's eligibility for the model general permit template, applicable

requirements not covered by the model general permit template, and the applicable procedural requirements of this rule.

11.1.8 Changes to the Proposed Decision

Changes to the proposed decision shall be governed by the following procedure:

11.1.8.1 The APCO may modify or change the proposed decision, the proposed permit, or the District analysis on the basis of information set forth in the comments received during the public comment period provided pursuant to subsection 11.1.4 and 11.1.5, or due to further analysis by the APCO. The APCO shall forward any such modified proposed decision, the proposed permit, the District analysis, and all necessary supporting information to the EPA. EPA shall be given 45 days to review the District's revised decision.

11.1.8.2 If the EPA objects pursuant to section 11.7 of this rule, the APCO shall either not issue the model general permit or model general permit template, or revise and submit a model permit which addresses the deficiencies identified by the EPA within 90 days.

11.1.9 Final Decision

If the EPA does not object pursuant to section 11.7 of this rule, the APCO shall issue the final model general permit or model general permit template.

11.1.10 Notification and Publication of Final Action

Written notification of the final decision shall be sent to the EPA, the ARB and any person and affected state that submitted comments during the public comment period. The APCO shall submit a copy of the model general permit or model general permit template as issued to the EPA and provide a copy to any person or agency requesting a copy. The APCO shall electronically publish such notice on the District’s website.

11.1.11 Public Inspection of Final Action Documents

No later than at the time that notice of final action is published on the District’s website, the APCO shall make available for public inspection at District offices a copy of the notice submitted for publication and all supporting documents. Information submitted which contains trade secrets shall be handled in accordance with Rule 1030 (Confidential Information) of these Rules and Regulations, with section 6254.7 of the Government

Code, and with relevant sections of the Administrative Code of the State of California. The contents of a permit issued under the requirements of this rule may not be considered a trade secret.

11.1.12 Public Petitions to the EPA

If the EPA does not object in writing to the District's preliminary decision during the EPA's 45 day review period, any person may petition the EPA within 60 days after the expiration of the EPA's 45 day review period. Any such petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided in section 11.1.4 of this rule, unless the petitioner demonstrates to the EPA that it was impracticable to raise such objections within such period, or unless grounds for such objections arose after such period. Petitions shall be based on the compliance of the permit provisions with applicable requirements.

11.2 General Permits

11.2.1 For applications meeting the qualifications as specified in a model general permit, the APCO may issue a general permit containing the terms and conditions of the model general permit without repeating the public participation procedures required under section 11.1.4 of this rule.

11.2.2 The APCO shall submit a copy of the application to the EPA within 30 days of receipt of a complete application.

11.2.3 If the EPA does not object pursuant to section 11.7 of this rule, the APCO shall issue the final general permit.

11.3 Initial Permits, Permit Renewals, New Sources, and Significant Permit Modifications

Except for permitting actions that qualify as general permits, minor modifications, or administrative amendments, all permits shall be issued subject to the following procedures:

11.3.1 Public Notification

11.3.1.1 The APCO shall provide a written notice of the proposed permit and, upon request, copies of the District analysis to interested parties. Interested parties shall include affected states, ARB and persons who have requested in writing to be notified. The notice, including a copy of the proposed permit, shall also be given by electronic publication on the District’s website and by any other means if necessary to assure adequate notice to the affected public. The public shall be given 30 days from the date

of publication to submit written comments on the District proposed action.

11.3.1.2 The notice shall provide the following information:

11.3.1.2.1 The identification of the source, the name and address of the permit holder, the activities and emissions change involved in the permit action;

11.3.1.2.2 The name and address of the District, the name and telephone number of District staff to contact for additional information;

11.3.1.2.3 The availability, upon request, of a statement that sets forth the legal and factual basis for the proposed permit conditions;

11.3.1.2.4 The location where the public may inspect the complete application, the District analysis, the proposed permit, and all relevant supporting materials;

11.3.1.2.5 A statement that the public may submit written comments regarding the proposed decision within at least 30 days from the date of publication and a brief description of commenting procedures; and

11.3.1.2.6 A statement that members of the public may request the APCO or his designee to preside over a public hearing for the purpose of receiving oral public comment, if a hearing has not already been scheduled. The APCO shall provide notice of any public hearing scheduled to address the proposed decision at least 30 days prior to such hearing.

11.3.1.3 The APCO shall provide written response to persons or agencies that submitted written comments which are postmarked by the close of the public notice and comment period. All written comments and responses to such comments shall be kept on file at the District office and made available upon request. The APCO shall notify the EPA and any affected State in writing of any refusal by the District to accept all recommendations for the proposed permit that the affected State submitted during the public or affected State review period. The notice shall include the District's reason for not accepting any such recommendation.

11.3.1.4 A copy of the complete application, the District analysis and the proposed permit shall be made available at District offices for public review and comment during normal business hours. The District analysis shall include a statement that sets forth the legal and factual basis for the proposed permit conditions, including references to the applicable statutory and regulatory provisions.

11.3.2 EPA Notification

The APCO shall provide written notice to the EPA of the proposed decision along with copies of the proposed permit, the District analysis, the public notice submitted for publication, and all necessary supporting information.

11.3.3 Changes to the Proposed Decision

Changes to the proposed decision shall be governed by the following procedure:

11.3.3.1 The APCO may modify or change the proposed decision, the proposed permit, or the District analysis on the basis of information set forth in the comments received during the public comment period provided pursuant to subsection 11.1.4 and 11.1.5, or due to further analysis by the APCO. The APCO shall forward any such modified proposed decision, the proposed permit, the District analysis, and all necessary supporting information to the EPA. EPA shall be given 45 days to review the District's revised decision.

11.3.3.2 If the EPA objects pursuant to section 11.7 of this rule, the APCO shall either not issue the permit, or revise and submit a permit which addresses the deficiencies identified by the EPA within 90 days.

11.3.4 Final Decision

If the EPA does not object pursuant to section 11.7 of this rule, the APCO shall issue the final permit.

11.3.5 Notification and Publication of Final Action

Written notification of the final decision shall be sent to the EPA, the ARB and any person and affected state that submitted comments during the public comment period. The APCO shall submit a copy of the permit as issued to the EPA and provide a copy to any person or agency requesting a copy. The APCO shall electronically publish such notice on the District’s website.

11.3.6 Public Inspection of Final Action Documents

No later than at the time that notice of final action is published on the District's website, the APCO shall make available for public inspection at District offices a copy of the notice submitted for publication and all supporting documents. Information submitted which contains trade secrets shall be handled in accordance with Rule 1030 (Confidential Information) of these Rules and Regulations, with section 6254.7 of the Government Code, and with relevant section of the Administrative Code of the State of California. The contents of a permit issued under the requirements of this rule may not be considered a trade secret.

11.3.7 Public Petitions to the EPA

If the EPA does not object in writing to the District's preliminary decision during the EPA's 45 day review period, any person may petition the EPA within 60 days after the expiration of the EPA's 45 day review period. Any such petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided in section 11.3.1 of this rule, unless the petitioner demonstrates to the EPA that it was impracticable to raise such objections within such period, or unless grounds for such objections arose after such period.

11.3.8 For permit applications utilizing or model general permit templates, public and agency comments on District's proposed actions shall be limited to the applicant's eligibility for the model general permit template, applicable requirements not covered by the model general permit template, and the applicable procedural requirements of this rule.

11.4 Minor Permit Modifications

11.4.1 Within 5 working days after the receipt of a complete application for a minor permit modification, the District shall provide notice of the requested modification to the EPA pursuant to section 11.3.2 of this rule, and affected states pursuant to section 11.3.1.1 of this rule.

11.4.2 An application requesting the use of minor permit modification procedures shall meet the requirements of section 7.0 of this rule and shall include the following:

11.4.2.1 A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

11.4.2.2 The source's suggested draft permit;

11.4.2.3 Certification by a responsible official that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used.

11.4.3 The District shall not issue a final permit modification until after a 45-day period review of the proposed permit modification by EPA or until EPA has notified the District that EPA will not object to issuance of the permit modification, whichever is first.

11.4.4 Within 90 days after District's receipt of an application for a minor permit modification or 15 days after the end of the EPA's 45-day review, whichever is later, the District shall do one of the following:

11.4.4.1 Issue the permit as proposed;

11.4.4.2 Deny the permit modification application;

11.4.4.3 Determine that the requested modification does not meet the minor permit modification criteria and should be reviewed pursuant to the administrative requirements for significant permit modifications; or

11.4.4.4 Revise the draft permit modification and transmit the new proposed permit modification to EPA and the affected states.

11.5 Administrative Permit Amendments

11.5.1 Within 60 days after receiving an application for an administrative change, the District shall do one of the following:

11.5.1.1 Take final action on the request incorporating the requested administrative amendments in the Part 70 permit; or

11.5.1.2 Determine that the requested amendments do not meet the Administrative Permit Amendment criteria and should be reviewed pursuant to the administrative requirements for minor or significant permit modifications.

11.5.2 A copy of the permit revised by administrative amendments shall be sent to the EPA within 10 days of the date that final action is taken.

11.5.3 Administrative amendments to permit conditions related to Title IV requirements shall be consistent with the requirements of 40 CFR part 72 and any District rule that implements the requirements of 40 CFR part 72.

11.6 Application Processing Deadlines

11.6.1 Completeness Determination

For all permitting actions except for applications for administrative amendments, the APCO shall determine whether the application is complete not later than 60 days after receipt of the application. If the APCO determines that the application is incomplete, the applicant shall be notified in writing of the decision specifying the information required. Unless the APCO requests additional information or otherwise notifies the applicant of incompleteness within 60 days of receipt of an application, the application shall be deemed complete. Upon receipt of any resubmittal of the application, a new 60-day period to determine completeness shall begin. Completeness of an application or resubmitted application shall be evaluated on the basis of the information requirements set forth in the District Rules and Regulations as they exist on the date on which the application or resubmitted application is received. Upon determination that the application is complete, the APCO shall notify the applicant in writing. The APCO may, during the processing of the application, request an applicant to clarify, amplify, correct, or otherwise supplement the information submitted in the application. The APCO shall submit a copy of the complete application to the EPA within five working days of the determination. The APCO need not provide notification for applications from sources that are not major sources when the EPA waives such requirements for a source category by regulation or at the time of approval of the District Part 70 permitting program.

11.6.2 Final Action

The APCO shall act on a complete application and take final action within the following time frames:

11.6.2.1 For an initial permit for a source subject to this rule on the date the rule becomes effective, no later than three years after the date the rule becomes effective.

11.6.2.2 For an initial permit for a source that becomes subject to this rule after the date the rule becomes effective, no later than 18 months after the complete application is received;

11.6.2.3 For a permit renewal, no later than 18 months after the complete application is received;

11.6.2.4 For a significant permit modification, no later than 18 months after the complete application is received;

11.6.2.5 For a minor permit modification, within 90 days after the application is received or 60 days after written notice to the EPA on the proposed decision, whichever is later; or

11.6.2.6 For any permit application with early reductions pursuant to section 112(i)(5) of the CAA, within 9 months after the complete application is received;

11.6.2.7 For applications for administrative amendments, no later than 60 days from receipt of the application.

11.7 EPA Objection

11.7.1 If the EPA objects in writing to the District's proposed decision within 45 days of being notified of the decision, the APCO shall not issue the permit.

11.7.2 Any EPA objection shall include a statement of the EPA's reasons for objection and a description of the terms and conditions that the permit must include to respond to the objections. The EPA shall provide the permit applicant a copy of the objection.

11.7.3 If the District fails, within 90 days after the date of EPA's objection to revise and submit a proposed permit in response to the objection, the EPA will issue or deny the permit in accordance with requirements of 40 CFR Part 70.

11.7.4 If the EPA objects to the permit as a result of a public petition, the APCO shall not issue the permit until EPA's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day review period and prior to an EPA objection. If the District has issued a permit prior to receipt of an EPA objection, the EPA will modify, terminate, or revoke such permit, and shall do so consistent with procedures in section 70.7(g)(4) or (5)(i) and (ii) of the 40 CFR regulations, and the District may thereafter reissue only a revised permit that satisfies EPA objection.

11.7.5 For applications for a Part 70 permit, EPA objection shall be limited to the compliance with applicable requirements and the requirements of 40 CFR part 70.

11.7.6 For applications utilizing model general permit templates, EPA's objection shall be limited to the applicant’s eligibility for the model general permit template, applicable requirements not covered by the model general permit template, and the applicable procedural requirements of this rule.

11.7.7 For applications for general permits, EPA's objection shall be limited to the applicant's eligibility for the model general permit and the applicable procedural requirements of this rule.

12.0 Reopening of Permits for Cause

12.1 Each issued permit shall include provisions specifying the conditions under which the permit will be reopened prior to the expiration of the permit. A permit shall be reopened and revised under any of the following circumstances:

12.1.1 The source becomes subject to additional applicable requirements and there is at least three years remaining on the permit term.

12.1.2 Additional requirements become applicable to Phase II acid rain facilities under the acid rain program. Upon approval by the District, excess emissions offset plans shall be deemed to be incorporated into the permit.

12.1.3 The District or EPA determine that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

12.1.4 The District or EPA determine that the permit must be revised or revoked to assure compliance with the applicable requirements.

12.2 Administrative requirements to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings made under section 12.1.1 of this rule shall be completed no later than 18 months after promulgation of the applicable requirement.

12.3 Reopenings under section 12.1 of this rule shall not be initiated before a notice of such intent is provided to the permittee by the APCO at least 30 days in advance of the date that the permit is to be reopened, except that the APCO may provide a shorter time period in the case of an emergency.

12.4 Reopenings for cause by EPA

12.4.1 If the EPA finds that cause exists to terminate, modify, or revoke and reissue a permit pursuant to sections 12.1.1 through 12.1.4 of this rule, the EPA will notify the District and the permittee of such finding in writing.

12.4.2 The District, within 90 days after receipt of such notification, forward to EPA a proposed determination of termination, modification, or revocation and reissuance, as appropriate. The EPA may extend this 90-day period for an additional 90 days if it finds that a new or revised permit application is

necessary or that the District must require the permittee to submit additional information.

12.4.3 The EPA will review the proposed determination from the District authority within 90 days of receipt.

12.4.4 The District shall have 90 days from receipt of an EPA objection to resolve any objection that EPA makes and to terminate, modify, or revoke and reissue the permit in accordance with the Administrator's objection.

12.4.5 If the District fails to submit a proposed determination pursuant to section 12.4.2 of this rule or fails to resolve any objection pursuant to paragraph 12.4.4 of this rule, the EPA will terminate, modify, or revoke and reissue the permit after taking the following actions:

12.4.5.1 Providing at least 30 days' notice to the permittee in writing of the reasons for any such action. This notice may be given during the procedures in sections 12.4.1 through 12.4.4 of this rule.

12.4.5.2 Providing the permittee an opportunity for comment on the EPA's proposed action and an opportunity for a hearing.

13.0 Compliance

13.1 Application Shield

13.1.1 Stationary sources for which timely and complete applications for initial permits have been submitted in accordance with the requirements of this rule may continue to operate under an application shield until the application is either approved or denied. Sources operating under the application shield shall not be in violation of the requirement of this rule to obtain a permit to operate. This requirement does not allow the source to operate in violation of any other requirement. The source is still required to comply with the requirements of District Rule 2010 (Permits Required). For the purpose of this subsection, an application may be deemed complete if all information required under section 7.0 of this rule, except for information required under subsections 7.1.3.3 through 7.1.3.10, is provided.

13.1.2 Stationary Sources for which timely and complete renewal applications have been submitted may continue to operate until the renewal is either issued or denied. Under the renewal application shield, the existing permit shall not expire and the conditions of the existing permit shall remain in effect until the renewal permit has been issued or denied.

13.1.3 The application shield is not applicable if the District's final action is delayed due to the failure of the responsible official of the source to submit timely

information requested by the District. The source must also submit additional information regarding applicable requirements that become applicable after a complete application is submitted, but before a draft permit is released.

13.2 Permit Shield

Compliance with permit conditions in part 70 permits that expressly state that a permit shield exists shall be deemed compliance with the applicable requirements on which the permit conditions are based, except for:

13.2.1 Requirements that become applicable after the permit is issued;

13.2.2 Requirements that become applicable with minor permit modifications, or any other changes, made without public comment; and

13.2.3 Requirements not specifically addressed in writing in response to an application for a permit or a revision to a permit. The permit shield applies only to requirements that are either identified and included by the District in the permit, or are requirements that the District, in acting on the application, determines in writing are not applicable to the source. In cases where the District determines that a requirement is not applicable to the source and provides a permit shield, the permit shall include the determination or a concise summary of the determination.

13.2.4 A part 70 permit that does not expressly state that a permit shield exists.

Notwithstanding these permit shield provisions, if a source that is operating under a general permit or a part 70 permit based on a general permit template is later determined not to qualify for the terms and conditions of the general permit or template, then the source is subject to enforcement action for operation without a part 70 permit. For sources operating under a part 70 permit based on a general permit template, if the source is later determined not to qualify for the template, only the portion of the facility covered by the template shall be subject to enforcement action for operation without a part 70 permit.

13.3 Penalties

Any person who violates any provision of this rule is guilty of a misdemeanor and is liable for a penalty as provided for in the California Health and Safety Code. Every day during any portion of which such violation occurs constitutes a separate offense.

Exhibit 6

District Rule 4455

RULE 4455 COMPONENTS AT PETROLEUM REFINERIES, GAS LIQUIDS PROCESSING FACILITIES, AND CHEMICAL PLANTS (Adopted April 20, 2005; Amended June 15, 2023)

1.0 Purpose

The purpose of this rule is to limit Volatile Organic Compound (VOC) emissions from leaking components at petroleum refineries, gas liquids processing facilities, and chemical plants.

2.0 Applicability

This rule shall apply to components containing or contacting VOC at petroleum refineries, gas liquids processing facilities, and chemical plants.

3.0. Definitions

3.1 APCO: The Air Pollution Control Officer of the San Joaquin Valley Unified Air Pollution Control District, or any person authorized to act on behalf of the APCO.

3.2 ARB: California Air Resources Board as established by the California Health and Safety Code Section 39510, or any person authorized to act on its behalf.

3.3 Background: a reading on a portable hydrocarbon detection instrument which is determined at a distance no greater than two (2) meter upwind from any component to be inspected and which is uninfluenced by any specific emission point.

3.4 Chemical Plant: an establishment that produces organic chemicals and/or manufactures products by organic chemical processes.

3.5 Closed-vent System: an APCO-approved system that is not open to the atmosphere and that is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gas or vapor from a piece or pieces of equipment to an APCO-approved control device that has a overall VOC collection and destruction or removal efficiency of at least 95%, or that transports gases or vapors back to a process system.

3.6 Commercial Quality Natural Gas: a mixture of gaseous hydrocarbons with at least 80 percent methane by volume (≥ 80 vol%) and less than ten percent by weight (<10 wt%) VOC as determined by the test method specified in Section 6.4.2, and meets the criteria specified in Public Utilities Commission (PUC) General Order 58-A.

3.7 Component: includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, flange, process drain, sealing mechanism, hatch, sight-glass, meter or seal fluid system in VOC service.

3.7.1 Major Component: any pump 5 brake horsepower or larger, any compressor, and any pressure relief device 4 inches in diameter or larger.

3.8 Component Type: includes, but is not limited to, any one (1) of the following groups: valves, fittings, threaded connections, pumps, compressors, pressure relief devices, pipes, flanges, process drains, sealing mechanisms, hatches, sight-glasses, and meters in VOC service.

3.9 Compressor: a device used to compress gases or vapors or a combination of gases and vapors by the addition of energy, and includes all associated components used for connecting and sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the compressor. For example, a valve that is connected to a threaded hole on body of the compressor, the first VOC leak point is the threaded connection on the body of the compressor, but the valve itself is not a "first VOC leak point". Similarly, a compressor shaft seal is considered as a first “VOC leak point”.

3.10 Compressor Part: for the purpose of Section 5.3.7, a compressor part refers to the “first VOC leak point” as explained in Section 3.9.

3.11 Critical Component: any component that would require the shutdown of a critical process unit if that component was shut down or disabled.

3.12 Critical Process Unit: a process unit that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

3.13 Critical Process Unit Shutdown: the shutdown of a critical process unit or part of the critical process unit that causes the entire unit to cease operating.

3.14 District: San Joaquin Valley Unified Air Pollution Control District.

3.15 Essential Component: a component that cannot be taken out of service without reducing, by more than 33 percent, the throughput of the process unit that it serves.

3.16 Flange: a projecting rim on a pipe used to attach it to another pipe or any other component in a piping system.

3.17 Fitting: a component, excluding flanges and threaded connectors, used to attach or connect pipes or piping system. Examples of a “fitting” include, but are not limited to quick-disconnect fitting, push-in-fittings, and cam-locks.

3.18 Gas Liquids Processing Facility: a facility that is engaged in the catalytic processing of gas liquids to produce finished products.

3.19 Gas/Vapor Service: a component is considered to be in gas/vapor service when the fluid in contact with the component contains VOCs and the fluid is primarily in gaseous state at operating conditions.

3.20 Inaccessible Component: a component located over 15 feet above ground when access is required from the ground; or a component located over six (6) feet away from a platform when access is required from the platform; or a component that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.

3.21 Inspection: means checking and/or testing of components in order to detect leaks.

3.21.1 Operator Inspection: inspection of components conducted by the operator pursuant to the inspection and re-inspection schedules specified in this rule for the purpose of demonstrating compliance with this rule.

3.21.2 District Inspection: inspection of components by District personnel or their representative to insure facilities and/or operators are in compliance with District requirements.

3.22 Leak: the dripping of VOC-containing liquid or the detection of a concentration of total organic compound, above background, determined according to the test method specified in Section 6.4.1 that exceeds the limits in Table 1 or Table 2, Section 3.22.1 and Section 3.22.2 of this rule. Any liquid or gas coming from a component undergoing repair or replacement, or during sampling of process fluid from a component into a container is not considered a leak provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

Table 1 – Gas Leak Standard in ppmv as Methane until June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	200 to 10,000	400 to 10,000
2. Threaded connections	Greater than 10,000	200 to 10,000	400 to 10,000
3. Flanges	Greater than 10,000	200 to 10,000	400 to 10,000
4. Pumps	Greater than 10,000	500 to 10,000	1,000 to 10,000
5. Compressors	Greater than 10,000	500 to 10,000	1,000 to 10,000
6. PRD	Greater than 10,000	100 to 10,000	200 to 10,000
7. Other component types not listed in 1 through 6 above	Greater than 10,000	500 to 10,000	1,000 to 10,000

Table 2 – Gas Leak Standard in ppmv as Methane after June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	200 to 10,000	400 to 10,000
2. Threaded connections	Greater than 10,000	200 to 10,000	400 to 10,000
3. Flanges	Greater than 10,000	200 to 10,000	400 to 10,000
4. Pumps	Greater than 10,000	500 to 10,000	500 to 10,000
5. Compressors	Greater than 10,000	500 to 10,000	500 to 10,000
6. PRD	Greater than 10,000	100 to 10,000	200 to 10,000
7. Other component types not listed in 1 through 6 above	Greater than 10,000	500 to 10,000	500 to 10,000

3.22.1 Major Liquid Leak: a visible mist or a continuous flow of liquid that is not seal lubricant.

3.22.2 Minor Liquid Leak: a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute.

3.23 Leak Minimization: reducing a leak to the lowest achievable level without damaging the component using best modern practices which include, but are not limited to, adding sealing material to the component, tightening the component, or adjusting the component without shutdown of the process that the component serves and that can be safely accommodated.

3.24 Liquid Service: a component is considered to be in liquid service when the fluid in contact with the component contains VOCs and the fluid is primarily liquid at operating conditions.

3.25 Open-ended Line or Valve: any line or valve, except for pressure relief devices and process drains, having one side of the line or valve seat in contact with the process fluid and one side open to the atmosphere, either directly or through an open piping.

3.26 Optical Gas Imaging (OGI): an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

3.27 Portable Hydrocarbon Detection Instrument: a hand-held hydrocarbon analyzer that meets the criteria specified in US EPA Method 21, 40 CFR Part 60. The instrument shall be calibrated with methane.

3.28 Pressure Relief Device (PRD): a pressure relief valve, or a rupture disc, and an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere.

3.29 Process Drain: any open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources. Drain origination points and drain termination points are not open-ended lines. Process drains are not open-ended lines.

3.30 Process Equipment: equipment that is used to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates.

3.31 Process Pressure Relief Device: a Pressure Relief Device (PRD) that is vented to the atmosphere and is located on a process equipment other than storage tanks, liquefied petroleum gas storage vessels, or pipelines used to transport materials.

3.32 Process System: an APCO-approved system that is not open to the atmosphere and is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gases or vapors from a piece of equipment to a process stream, fuel gas system, or sales gas system.

3.33 Pump: a device used to transport fluids by the addition of energy, and includes all associated components used for connecting or sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the pump. For example, a valve that is connected to a threaded hole on body of the pump, the first VOC leak point is the threaded connection on the body of the pump, but the valve itself is not a "first VOC leak point". Similarly, a pump shaft seal is considered as a first “VOC leak point”.

3.34 Pump Part: for the purpose of Section 5.3.7, a pump part refers to the “first VOC leak point” as explained in Section 3.33.

3.35 Refinery: an establishment that processes petroleum as defined in the Standard Industrial Classification Code under 2911 (Petroleum Refining).

3.36 Release: a VOC emission to the atmosphere from process PRD caused by an increase in upstream pressure. A leak caused by improper reseating of the PRD is not a release.

3.37 Rupture Disk: a rigid diaphragm held between flanges for the purpose of isolating organic compounds from the atmosphere or from a downstream pressure relief device. Most rupture disks are designed to fail at a certain pressure point.

3.38 Tag: a piece of paper, metal, plastic or other suitable material that is attached to a component for the purpose identification or other information.

3.39 Turnaround: scheduled shutdown of a process unit for maintenance and repair work.

3.40 Sight glass: a device located on a fluid line or a process vessel that allows an operator to view the product or material inside a fluid line or a process vessel.

3.41 Unsafe-to-Monitor Component: a component that is installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.

3.42 US EPA: United States Environmental Protection Agency

3.43 Vacuum Service: operating under a negative gauge pressure or below atmospheric pressure.

3.44 Valve: a device that regulates the flow of fluid in a piping system by means of an external actuator acting to permit or block passage of fluid.

3.45 Volatile Organic Compound (VOC): as defined in Rule 1020 (Definitions).

4.0 Exemptions

4.1 The requirements of this rule shall not apply to components subject to Rule 4623 (Storage of Organic Liquids).

4.2 Except for complying with the applicable requirements of Sections 6.1 and 7.2, the requirements of this rule shall not apply to components described in Sections 4.2.1 through 4.2.8. An operator claiming an exemption pursuant to Section 4.2 shall provide proof of the applicable criteria to the satisfaction of the APCO.

4.2.1 Pressure relief devices, pumps, and compressors equipped with a closed-vent system as defined in Section 3.0.

4.2.2 Components buried below ground.

4.2.3 Components exclusively handling liquid streams which have less than 10 percent by weight (<10 wt%) evaporation at 150^0 C as determined by the test method specified in Section 6.4.3.

4.2.4 Components exclusively handling liquid streams with a VOC content less than ten percent by weight (<10 wt%), as determined by the test methods in Section 6.4.2.

4.2.5 Components exclusively handling gas/vapor streams with a VOC content of less than one percent by weight (<1wt%), as determined by the test method specified in Section 6.4.2.

4.2.6 Components incorporated in lines exclusively in vacuum service.

4.2.7 Components exclusively handling commercial natural gas.

5.0 Requirements

5.1 Operating Requirements

5.1.1 The operator shall not use any component that leaks in excess of the applicable leak standards of this rule, or that is found to be in violation of the provisions specified in Section 5.1.3. Components that have been found leaking in excess of the applicable leak standards of this rule may be used provided such leaking components have been identified with a tag for repair, are repaired, or are awaiting re-inspection after being repaired, within the applicable time period specified in this rule.

5.1.2 Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

5.1.3 Determination of Compliance with the Leak Standards

5.1.3.1 District Inspection

The operator shall be in violation of this rule if any District inspection demonstrates that one or more of the conditions in Sections 5.1.4 exist at the facility.

5.1.3.2 Operator Inspection

5.1.3.2.1 Except for annual operator inspection described in Section 5.1.3.2.3, any operator inspection that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall not constitute a violation of this rule if the leaking components are repaired as soon as practicable but not later than the time frame specified in this rule. Such components shall not be counted towards determination of compliance with the provisions of Section 5.1.4.

5.1.3.2.2 Leaking components detected during operator inspection pursuant Section 5.1.3.2.1 that are not repaired, replaced, or removed from operation as soon as practicable but not later than the time frame specified in this rule shall be counted toward

determination of compliance with the provisions of Section 5.1.4.

5.1.3.2.3 Any operator inspection conducted annually for a component type (including operator annual inspections pursuant to Section 5.2.5, 5.2.6, 5.2.7, or 5.2.8) that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall constitute a violation of this rule regardless of whether or not the leaking components are repaired, replaced, or removed from operation within the allowable repair time frame specified in this rule.

5.1.4 Leak Standards

For the purpose of this rule, a component shall be considered in violation if one or more of the conditions specified in Sections 5.1.4.1 through 5.1.4.4 exist at the facility.

5.1.4.1 An open-ended line or a valve located at the end of the line that is not sealed with a blind flange, plug, cap; or a second closed valve that is not closed at all times, except during attended operations requiring process fluid flow through the open-ended lines. Attended operations include draining or degassing operations, connection of temporary process equipment, sampling of process streams, emergency venting, and other normal operational needs, provided such operations are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

5.1.4.2 A component with a major liquid leak.

5.1.4.3 A component with a gas leak greater than 50,000 ppmv.

5.1.4.4 A component leak described in Sections 5.1.4.4.1 through 5.1.4.4.3 and numbering in excess of the maximum allowable number or percent specified in Table 3.

5.1.4.4.1 A minor liquid leak; or

5.1.4.4.2 A minor gas leak; or

5.1.4.4.3 A gas leak greater than 10,000 ppmv up to 50,000 ppmv.

Table 3 – Maximum Allowable Number or Percent of Leaking Components Per Inspection Period

Component Type	Maximum Number of Leaks for 200 or less Components Inspected	Maximum Percent or Number of Leaks for more than 200 Components Inspected*
1. Valves	1	0.5% of number inspected
2. Threaded Connections	1	0.5% of number inspected
3. Flanges	1	0.5% of number inspected
4. Pumps	2	1.0% of number inspected
5. Compressors	1	1 leak
6. PRD	1	1 leak
7. Other component types not listed in items 1 through 6 above	1	1 leak
8 Pipes	Maximum Number of Leaks	
	2	

*The maximum number of leaks in Table 3 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components of a given type inspected during the specified inspection period. Leaks counted toward the allowable leaks in Table 3 are still subject to maintenance and repair requirements of Section 5.3.

5.2 Inspection and Re-Inspection Requirements

5.2.1 The operator shall audio-visually (by hearing and sight) inspect for leaks all accessible operating pumps, compressors, and PRDs in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours.

5.2.2 Any audio-visual inspection of all accessible operating pumps, compressors, and PRDs in service performed by an operator that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected using the test method specified in Section 6.4.1 not later than 24 hours after conducting the audio-visual inspection. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table 4 or Table 5 of this rule.

5.2.3 Notwithstanding the requirement of Sections 5.2.1 and 5.2.2, the operator shall inspect all components at least once every calendar quarter using the test method specified in Section 6.4.1, except for inaccessible components, unsafe-to-monitor components, or pipes. Inaccessible components and unsafe-to-monitor components shall be inspected in accordance with the provisions of Sections 5.2.5 and 5.2.6, respectively. Pipes shall be inspected in accordance with the provisions of Section 5.2.7.

5.2.4 The operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using the test method specified in Section 6.4.1.

5.2.5 The operator shall inspect all inaccessible components at least once every 12 months using the test method specified in Section 6.4.1.

5.2.6 The operator shall inspect all unsafe-to-monitor components during each turnaround using the test method specified in Section 6.4.1.

5.2.7 The operator shall visually inspect all pipes for leaks at least once every 12 months.

5.2.7.1 Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected using the test method specified in Section 6.4.1 not later than 24 hours after conducting the audio-visual inspection. If a leak is found, the leak shall be repaired as soon as practicable but not later than the timeframe specified in Table 4 or Table 5 of this rule.

5.2.7.2 The operator may conduct the annual pipe inspection required by Section 5.2.7 in conjunction with the annual pipe inspection required by the Spill Prevention Control and Countermeasure Plan pursuant to 40 Code of Federal Regulation Part 112 (Oil Prevention and Response: Non-Transportation-Related Onshore and Offshore Facilities). Records of annual pipe inspection required by SPCC may be used to document the inspection required by Section 5.2.7. The operator shall maintain the records of such inspections at the facilities. The records shall be made available to the APCO, ARB, and US EPA upon request.

5.2.8 Until June 30, 2024, notwithstanding the requirement of Section 5.2.3, the operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, or an operator who is already on an annual inspection frequency on or before (rule adoption date) may apply for a written approval from the APCO to continue conducting annual inspections for a component type, provided the operator meets all the criteria specified in Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis.

5.2.8.1 The operator was not in violation of any provision of Sections 5.1 during five consecutive quarterly inspections for that component type.

5.2.8.2 The operator did not receive a Notice of Violation from the APCO during the previous 12 months for violating any provisions of this rule for that component type.

5.2.8.3 The written request shall include pertinent documentation to demonstrate that the operator has successfully met the requirements of Sections 5.2.8.1 and 5.2.8.2.

5.2.9 Until June 30, 2024, the annual inspection frequency approved by the APCO pursuant to Section 5.2.8 shall revert to quarterly inspection frequency for a component type if either one of the following occurs:

5.2.9.1 Operator inspection or District inspection demonstrates that a violation of the provisions of Sections 5.1, 5.2, and 5.3 exists for that component type, or

5.2.9.2 The APCO issued a Notice of Violation for violating any of the provisions of this rule during the annual inspection period for that component type.

5.2.10 Until June 30, 2024, when the inspection frequency changes from annual to quarterly inspections pursuant to Section 5.2.9 above, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency. The written notification shall include the reason(s) and date of change to quarterly inspection frequency.

5.2.11 The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. The operator shall re-inspect the process PRD using the test method specified in Section 6.4.1 not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release to insure that the process PRD is operating properly, and is leak-free. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections.

5.2.12 Except for process PRD subject to the requirements of Section 5.2.11, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using the test method specified in Section 6.4.1.

5.2.13 A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered a willful circumvention of the rule and is a violation of this rule.

5.3 Maintenance Requirements

5.3.1 Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag.

5.3.2 The tag shall remain affixed to the component until all the conditions specified in Sections 5.3.2.1 through 5.3.2.3 have been met.

5.3.2.1 The leaking component has been repaired or replaced; and

5.3.2.2 The component has been re-inspected using the test method in Section 6.4.1; and

5.3.2.3 The component is found to be in compliance with the requirements of this rule.

5.3.3 The tag shall include the following information:

5.3.3.1 Date and time of leak detection.

5.3.3.2 Date and time of leak measurement.

5.3.3.3 For gas leaks, indicate the leak concentration in ppmv.

5.3.3.4 For liquid leaks, indicate whether it is a major liquid leak or a minor liquid leak.

5.3.3.5 For essential components, unsafe–to-monitor components, or critical components, so indicate on the tag.

5.3.4 An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere.

5.3.5 If the leak has been minimized but the leak still exceeds the applicable leak standards of this rule, an operator shall comply with at least one of the requirement of Sections 5.3.5.3, 5.3.5.4, or 5.3.5.5 as soon as practicable but not later than the time period specified in Table 4 or Table 5. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Table 4 or Table 5, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required.

5.3.5.1 The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table 4 or Table 5.

5.3.5.2 The start of the repair period shall be the time of the initial leak detection.

5.3.5.3 Repair or replace the leaking component; or

5.3.5.4 Vent the leaking component to a closed vent system as defined in Section 3.0.

5.3.5.5 Remove the leaking component from operation.

Table 4 – Repair Period Until June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 1)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	2	0
Liquid Leaks		
Minor Liquid Leak (See Section 3.22.2)	3	0
Major Liquid Leak (See Section 3.22.1)	2	0

Table 5 – Repair Period After June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 2)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

5.3.6 If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall:

5.3.6.1 Minimize the leak within one hour after detection of leaks; and

5.3.6.2 If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of this rule, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier.

5.3.7 For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6.

5.3.7.1 Replace or retrofit the component with the control technology specified in Table 6. Notify the APCO in writing prior to replacing or retrofitting the component; or

Table 6 – Component Control Technology Replacement/Retrofit

Component Type	Control Technology
Compressors	Replace existing seal with dual mechanical seal, oil-film seal, gas seal, or face-type seal.
Pumps	Replace with seal-less pump or replace with dual mechanical seal.
PRD	Replace PRD and install a rupture disc in the line which precedes the PRD such that the PRD is in series with and follow the rupture disc.
Valves	Replace with sealed bellows valve, or graphite or teflon chevron seal rings in a live-loaded packing gland.
Threaded Connections	Weld connections or replace threaded connections with flanges.
Sampling Connections	Replace with closed-loop sampling system

5.3.7.2 Replace the component with Achieved-in-Practice Best Available Control Technology (BACT) equipment, as determined in accordance with Rule 2201 (New and Modified Stationary Source Review Rule), and as approved by the APCO in writing; or

5.3.7.3 Vent the component to an APCO approved closed vent system as defined in Section 3.0; or

5.3.7.4 Remove the component from operation.

5.3.7.5 For any component that is accessible, is not unsafe-to-monitor, is not an essential component, is not a critical component, the operator shall comply with the requirement of Section 5.3.7.1, Section 5.3.7.2, Section 5.3.7.3, or Section 5.3.7.4 as soon as practicable but not later than twelve (12) months after the date of detection of the fifth major leak within a continuous 12-month period as indicated in Section 5.3.7.

5.3.7.6 For any inaccessible component, unsafe-to-monitor component, essential component, or critical component, the operator shall comply with the requirement of Section 5.3.7.1, Section 5.3.7.2, Section 5.3.7.3, or Section 5.3.7.4 as soon as practicable but not later than the next turnaround or not later than two (2) years after the date of detection of the fifth major leak within a continuous 12-month period as indicated in Section 5.3.7, whichever comes earlier.

5.4 Process PRD Requirements

5.4.1 The operator shall monitor process PRD by using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process PRD where parameter monitoring is not feasible.

5.4.2 By October 20, 2005, the operator shall submit to the APCO a compliance plan, as part of the Operator Management Plan required by Section 6.1, containing the inventory of process PRD by size, set pressure and location, and the type of monitoring system to be used in order to comply with the requirement of Section 5.4.1. If applicable, the operator shall indicate the process parameter selected for continuous monitoring and the justification for such selection.

5.4.3 The operator shall comply with the process PRD release notification and recordkeeping requirements specified in Section 6.3.

5.4.4 After a release from process PRD in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable but not later than 30 days to prevent the reoccurrence of similar release. For refineries processing greater than 20,000 barrels of crude oil per day, any

subsequent release in excess of 500 pounds of VOC within a continuous 24-hour period shall be subject to the requirements of Section 5.4.5.

5.4.5 The operator of a refinery processing greater than 20,000 barrels of crude oil per day shall connect all process PRD serving that process equipment to an APCO-approved closed vent system as defined in Section 3.0 if any of the condition specified in Sections 5.4.5.1 and 5.4.5.2 occurs. Process PRD subject to the provisions of Section 5.4.5 shall be connected to an APCO-approved closed vent system as soon as practicable, but no later than the first turnaround after the requirement to connect becomes effective.

5.4.5.1 A second release from any process PRD serving the same piece or pieces of equipment and each release is in excess of 500 pounds of VOC in a continuous 24-hour period and provided the second release occurs within any five year period of the first release.

5.4.5.2 Any release in excess of 2,000 pounds of VOC in a continuous 24-hour period, from any process PRD serving the same piece or pieces of process equipment.

5.5 Component Identification Requirements

5.5.1 All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator or District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but not later than 24 hours after discovery.

5.5.2 The operator shall comply with the requirements of Sections 6.1.4 if there is any change in the description of major components or critical components.

6.0 Administrative and Recordkeeping Requirements

6.1 Operator Management Plan

6.1.1 By October 20, 2005, an operator whose existing components are either subject to the rule or whose existing components are exempt pursuant to Section 4.2 on or before April 20, 2005 shall submit an Operator Management Plan for approval by the APCO.

6.1.2 The operator shall keep a copy of the APCO-approved Operator Management Plan at the facility and make it available to the APCO, ARB and US EPA upon request.

6.1.3 The operator shall describe in the Operator Management Plan all components subject to this rule and all components that are exempt pursuant to Section 4.0 of this rule or part of this rule. The Plan shall contain a description of the procedures that the operator will use to comply with the requirements of this rule. The Plan shall include, at a minimum all of the following information:

6.1.3.1 Identification and description of any known hazard that might affect the safety of an inspector.

6.1.3.2 Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following information:

6.1.3.2.1 Except for pipes, the number of components that are subject to this rule by component type and type of service (i.e., liquid service or gas/vapor service).

6.1.3.2.2 Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components, that are subject to this rule, including the reason(s) for such designation.

6.1.3.2.3 Except for pipes, the location of components that are subject to this rule (components may be grouped together functionally by process unit or facility description).

6.1.3.2.4 Except for pipes components exempt pursuant to Section 4.2 (except for components buried below ground) may be described in the Operator Management Plan by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the exemption criteria for components for which an exemption is being claimed pursuant to Sections 4.2 shall be submitted with the Operator Management Plan.

6.1.3.3 Detailed schedule of inspection to be conducted as required by this rule.

6.1.3.4 Include the compliance plan for process PRD as required by Section 5.4.2 of this rule.

6.1.3.5 Specify whether a qualified contractor or in-house team will perform the inspections.

6.1.3.6 Establish an employee training program for inspecting, repairing, and recordkeeping procedures, as necessary.

6.1.3.6.1 Specify the training standards for personnel performing inspections and repairs.

6.1.3.6.2 Document the leak detection training using the test method in Section 6.4.1 for new operators, and for experienced operators, as necessary.

6.1.3.6.3 The operator shall maintain copies of the training records at the facility. Copies of the training records shall be made available to the APCO, ARB, and US EPA upon request.

6.1.4 By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any or no changes to an existing Operator Management Plan.

6.1.5 The APCO shall provide written notice to the operator of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Plan. If the APCO fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of this rule.

6.2 Inspection Log

6.2.1 An operator at each facility shall maintain an inspection log containing, at a minimum, the following information:

6.2.1.1 Total number of components inspected, and total number and percentage of leaking components found by component types.

6.2.1.2 Location, type, name or description of each leaking component, and description of any unit where the leaking component is found.

6.2.1.3 Date of leak detection and method of leak detection.

6.2.1.4 For gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record whether the leak is a major liquid leak or a minor liquid leak.

6.2.1.5 Date of repair, replacement, or removal from operation of leaking components.

6.2.1.6 Identification and location of essential component and critical components found leaking that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier.

6.2.1.7 Methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier.

6.2.1.8 After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv.

6.2.1.9 Inspector's name, business mailing address, and business telephone number.

6.2.1.10 The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.

6.2.2 Until June 30, 2024, records of leaks detected by quarterly or annual operator inspection, and each subsequent repair and re-inspection, shall be submitted to the APCO, ARB, or US EPA upon request.

6.2.3 After June 30, 2024, records of leaks detected by operator inspection, and each subsequent repair and re-inspection, shall be submitted to the APCO, ARB, and US EPA upon request.

6.2.4 Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.

6.2.5 Copies of all records required by Section 6.2 of this rule shall be retained for a minimum of five (5) years after the date of an entry. Such records shall be made available to the APCO, ARB, and US EPA upon request.

6.3 Process PRD Release Notification

6.3.1 The operator shall notify the APCO, by telephone or other methods approved by the APCO, of any process PRD release described in Sections 5.4.4 and 5.4.5, and any release in excess of the reportable quantity limits as stipulated in 40 CFR, Part 117, Part 302 and Part 355, including any release in excess of 100 pounds of VOC, within one hour of such occurrence or within one hour of the time said person knew or reasonably should have known of its occurrence.

6.3.2 The operator shall submit a written report to the APCO within thirty (30) calendar days of following notification of process PRD release subject to 6.3.1. The written report shall include all of the following information:

6.3.2.1 Process PRD type, size, and location.

6.3.2.2 Date, time and duration of the process PRD release.

6.3.2.3 Types of VOC released and individual amounts, in pounds, including supporting calculations.

6.3.2.4 Cause of the process PRD release.

6.3.2.5 Corrective actions taken to prevent a subsequent process PRD release.

6.3.3 The operator shall keep records of the process (s) parameters monitored pursuant to Section 5.4.1 for a period of five (5) years, and make the records available to the APCO, ARB, and US EPA upon request.

6.4 Test Methods

Equivalent test methods other than specified in Sections 6.4.1 through 6.4.5 may be used provided such test methods have received prior approval from the US EPA, ARB, and APCO.

6.4.1 Measurements of gaseous leak concentrations shall be conducted according to US EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in US EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument.

6.4.1.1 After June 30, 2024, All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21

within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 5.

6.4.2 The VOC content shall be determined using American Society of Testing and Materials (ASTM) D 1945-14 for gases and South Coast Air Quality Management District (SCAQMD) Method 304-91 for liquids.

6.4.3 The percent by volume liquid evaporated at 150^0C shall be determined using ASTM D 86-82.

6.4.4 The control efficiency of any VOC control device, measured and calculated as carbon, shall be determined by US EPA Method 25, except when the outlet concentration must be below 50 ppm in order to meet the standard, in which case Method 25a may be used. US EPA Method 18 may be used in lieu of US EPA Method 25 or US EPA Method 25a provided the identity and approximate concentrations of the analytes/compounds in the sample gas stream are known before analysis with the gas chromatograph and the gas chromatograph is calibrated for each of those known analyte/compound to ensure that the VOC concentrations are neither under- or over-reported.

6.4.5 Halogenated exempt compounds shall be analyzed by US EPA Method 18 or ARB Method 422 "Determination of Volatile Organic Compounds in Emission from Stationary Sources."

7.0 Compliance Schedule

7.1 Until June 30, 2024, operators may continue performing their quarterly inspection schedules that exist on or before April 20, 2005. Operators who are already on an annual inspection frequency on or before April 20, 2005, may apply for a written approval from the APCO to continue conducting annual inspections provided the operators meet all the criteria specified in Sections 5.2.8.

7.2 Any component that is exempt pursuant to Section 4.2 that becomes subject to all the requirements of this rule through the loss of exemption status shall be in compliance with this rule on and after the date the exemption status is lost.

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Exhibit 7

APR 1150

San Joaquin Valley Unified
Air Pollution Control District

APR 1150

Implementation of Rule 2201
for SB 288 Major Modifications and Federal Major Modifications

Approved By: Signed Brian Clements Director of Permit Services	Date: March 17, 2016 Revised: September 16, 2020 Revised: October 01, 2020 Revised: December 02, 2020 Revised: January 05, 2021 Revised: July 26, 2023

I. Purpose

The purpose of this policy is to provide guidance on the calculation procedures to determine if a project is a California Senate Bill 288 (SB 288) Major Modification and/or a Federal Major Modification. Additionally, for projects that are Federal Major Modifications, this policy provides guidance for determining the Federal Offset Quantity (FOQ), which is used in offset equivalency determinations.

Please note that nothing in this policy supersedes the requirements of subject to District Rule 2201 (*New and Modified Stationary Source Review Rule*) or federal New Source Review as codified on 40 CFR 51.165 and part D of Title I of the Federal Clean Air Act.

II. Resources

- Federal Non-attainment New Source Review Permit Requirements - 40 CFR 51.165
- Federal Emission Offset Interpretative Ruling - Appendix S to Part 51
- Federal Clean Air Act: https://www.epa.gov/clean-air-act-overview/clean-air-act-text
- Federal Clean Air Act under section 182 (e) (2): https://www.govinfo.gov/content/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart2-sec7511a.htm
- EPA's Proposed Reconsideration of Fugitive Emissions Rule: https://www.epa.gov/nsr/proposed-reconsideration-fugitive-emissions-rule

III. SB288 Major Modification, Federal Major Modification, and New Major Source

An SB 288 Modification or a Federal Major Modification for a given pollutant can only occur at a stationary source that is major for that specific pollutant. Emission increases at non-major sources cannot trigger an SB288 Major Modification or a Federal Major Modification.

The determination of whether various permitting actions involving new or modified emission units are part of the same project is to be performed on a case by case basis. **In general, new or modified emission units that are technically or economically dependent shall be considered one project for SB 288 Major Modification and Federal Major Modification applicability (see 71 FR 54235)**. Please note that in this context, the term "project" has no relation to the project number assigned by the District to individual groups of applications.

Non-road engines shall not be considered in determining whether a source is major source or if a modification is a SB288 or Federal Major Modification. The Federal CAA reserves the regulation of non-road engines to Title II (National Emission Standards) of the CAA. While Title 1 (Nonattainment Areas) does not include explicit provisions to exclude non-road engine from applicability determinations, Title III (Toxics) includes a provision in the definition of stationary source that excludes "… those emissions … from a non-road engine or a non-road vehicle defined in section 216".

SB 288 Major Modification

The SB 288 Major Modification calculation procedure is included in Rule 2201 to comply with the requirements of California SB 288 which prohibited Districts from relaxing requirements for Federal New Source Review (as it existed on 12/19/02) as a result of Federal NSR reform.

40 CFR Part 51.165 (as it existed on 12/19/02) defines a Major Modification as any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

Rule 2201
SB 288 Major Modification Thresholds

POLLUTANT	THRESHOLD (POUNDS PER YEAR)
VOC	50,000
NOx	50,000
PM10	30,000
SOx	80,000

Federal Major Modification

Rule 2201 section 3.21 defines Federal Major Modification the same as "Major Modification" as defined in 40 CFR 51.165. As defined in 40 CFR 51.165, Section (a)(1)(v), a Federal Major Modification is any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act. The significant net emission increase threshold for each criteria pollutant is included in Rule 2201 (see table below).

Rule 2201
Federal Major Modification Significance Thresholds

POLLUTANT	THRESHOLD (POUNDS PER YEAR)
VOC	0
NOx	0
PM2.5	20,000 of direct PM2.5 emissions or
	80,000 of sulfur dioxide emissions or
	80,000 of nitrogen oxide emissions
PM10	30,000
SOx	80,000

New Major Source

Pursuant to Rule 2201 section 3.30, emission increases at a non-major source (or at new sources) constitute a New Major Source if the emission increase for a given pollutant is as large as the major source threshold for that pollutant, i.e. the project by itself would result in a net emission increase exceeding the major source threshold.

Fugitive emissions are included in determining whether a new or existing source is a New Major Source only when the source belongs to one of the specific source categories listed in 40 CFR 51.165(a)(1)(iv)(C).

Other than described above, there are no "federal" requirements for projects at existing sources that result from a project that causes a source's potential to emit to exceed the major source threshold.

IV. SB 288 Major Modification Calculation

40 CFR 51.165 that existed on 12/19/2002 (See Appendix A) , states that for a major source, a project is a Major Modification if the project results in a net emission increase exceeding the SB 288 Major Modification Thresholds listed in Rule 2201.

Under this version of 40 CFR 51.165 (12/19/2002), **a Net Emission Increase is defined as the sum of the differences between the post-project potential to emit (PE2) and the actual emissions (AE) for all new and modified emission units**.

NEI = ∑(PE2 – AE)

The project's Net Emissions Increase for each pollutant is equal to:

- **For existing emission units: the sum of the differences between the potential to emit (PE) and the actual emissions (AE)**

  Project Net Emissions Increase = ∑(PE2 – AE)

or

- **For new emission units: the sum of the potentials to emit**.

  Project Net Emissions Increase = ∑(PE2)

This calculation is done on a pollutant-by-pollutant basis and **only for those pollutants for which the source is major.**

In determining which emission units are new or modified, the definitions in the appropriate version of 40 CFR 51.165 shall be used, and not the definitions in Rule 2201.

For existing emissions unit, when determining whether a unit is included in the SB 288 Major Modification applicability calculation, only unit(s) undergoing a physical change or an actual change in the method of operation must be included. If an emission unit is not undergoing a physical change or an actual change in the method of operation, it must not be included in the SB 288 Major Modification applicability calculation.

For purposes of determining if a new or modified emission unit is part of an SB 288 Major Modification, if the annual emission increase for the emission unit when divided by 365 is less than or equal to 0.5 lb/day, such an increase shall be rounded to 0. New or modified emission units with emission increases that round to 0 shall not constitute an SB 288 Major Modification.

The process for determining if a project will result in a SB 288 Major Modification consists of a two-step test:

- **The first step is to determine if the project results in a significant emission increase.** For this determination, only emission increases are counted. Emission decreases associated with the project are not counted.
- The second step is to determine if the project results in a **significant <u>net</u> emission increase**.

<u>Calculations for existing emission units:</u>

- PE: The potential to emit is the post-project potential to emit for the emission unit.
- AE: In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

<u>Calculations for new emission units:</u>

- The potential to emit is the post project potential to emit for the emission unit.
- The actual emissions are equal to 0.

- A replacement unit (a unit that replaces the function of an existing unit) shall be treated as an existing emission unit.

Fugitive Emissions:

Fugitive emissions must be included in the analysis when determining whether a SB 288 Major Modification is triggered.

Conclusion:

If the project's emission increases are less than the significance thresholds, the project is not an SB 288 Major Modification and no further analysis is required. However, if the project's emission increases are above the SB 288 Major Modification significance thresholds, the project results in a significant emission increase and the second step of the test must be completed.

If the project results in a significant emission increase, then the second step is to determine if all creditable emission increases and decreases within the past five years (including those projects not related to the subject project) results in a significant net emission increase. In this calculation, all creditable emission decreases and increases must be counted.

If the net emission increase is less than the significance thresholds in Table 3-5 of Rule 2201, the project is not an SB 288 Major Modification and no further analysis is required.

Alternatively, the applicant may stipulate that the project results in both a significant emission increase and significant net emission increase. In such a case, the project constitutes an SB 288 Major Modification and is subject to all applicable requirements.

V. Federal Major Modification Applicability Calculation

The calculations below are strictly to determine if a modification at a stationary source is a Federal Major Modification. For projects that are a Federal Major Modification, the Federal Offset Quantity is discussed in Section VI below.

This calculation is done on a pollutant-by-pollutant basis and only for those pollutants for which the source is major.

In determining which emission units are new or modified, the definitions in the appropriate version of 40 CFR 51.165 shall be used, and not the definitions in Rule 2201.

For existing emissions units, when determining whether a unit is included in the Federal Major Modification applicability calculation, only unit(s) undergoing a physical change or an actual change in the method of operation must be included. If an emission unit is not undergoing a physical change or an actual change in the method of operation, it must not be included in the Federal Major Modification applicability calculation.

It should be noted that the replacement of an entire emissions unit that results in a Federal Major Modification does not qualify as a Routine Replacement Emissions Unit in Rule 2201 section 3.38.

The remaining discussion addresses procedures to determine if a project's emission increase or net emission increase is significant as specified in Rule 2201 section 3.21.1-6. This policy does not address the PAL exclusion as defined in Rule 2201 section 3.21.7.

For purposes of determining if a new or modified emission unit is part of an Federal Major Modification, if the annual emission increase (calculated using the procedures below) for the emission unit when divided by 365 is less than or equal to 0.5 lb./day, such an increase shall be rounded to 0. New or modified emission units with emission increases that round to 0 shall not constitute a Federal Major Modification.

The first step is to determine if the project itself results in a significant emission increase. In this determination, only emission increases are counted. Emission decreases associated with the project are not counted.

The second step is to determine if the project results in a significant net emission increase.

Please note that as required in the Federal Clean Air Act under section 182 (e) (2), Step 2 of the analysis shall not be performed for pollutant or their precursors for which a district is in extreme non-attainment status. For the District, this requirement applies to NOx and VOC. Therefore for NOx and VOC, only step 1 of the analysis is performed when determining Federal Major Modification applicability.

Notwithstanding the above, a facility with a project that has an emission increase in NOx or VOCs can elect to offset the emission increase at a ratio of 1.3:1 using internal emission reductions as defined in Rule 2201 section 3.27. Such emission reductions must be surplus of all current Federally enforceable requirements, i.e. surplus at the time of use.

Fugitive Emissions:

Fugitive emissions must be included in the analysis when determining whether a Federal Major Modification is triggered.

1. Step 1: Project Emissions Increase Calculation

1.1. Calculation for Modification to Existing Emission Units

Replacement Unit: A replacement unit (as defined in 51.165(a)(1)(xxi) shall be treated as an existing emission unit in applicability calculations pursuant to 51.165(a)(1)(vii)(B).

- **Project Emissions Increase**

  For existing emission units, according to 40 CFR 51.165(a)(2)(ii)(C), the project's emission increase for each pollutant is equal to the sum of the

differences between the projected actual emissions (PAE) and the baseline actual emissions (BAE):

Project emissions increase = ∑(PAE – BAE)

- **Baseline Actual Emissions**

BAE definition:
For emission units (other than electric utility steam generating units), according to according to 40 CFR 51.165(a)(1)(xxxv)(B), **the BAE are calculated as the average, in tons/year, at which the emissions unit actually emitted during any 24-month period selected by the operator within the previous 10-year period.** For electric utility steam generating units the BAE are calculated based on any 24-month period selected by the operator within the previous 5-year period.

Adjustments to BAE:
BAE must be adjusted to
- Include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions,
- Exclude any non-compliant operation emissions.

The evaluation shall document any such adjustments or that none adjustments were required.

There are no special provisions in determining baseline actual emissions for emission units for which offsets were previously provided.

BAE For Each Regulated Pollutant:
For a specific regulated NSR pollutant, when a project involves multiple emissions units, **only one consecutive 24-month period must be used** to determine the baseline actual emissions for all modified emissions units.

A different consecutive 24-month period can be used **for each regulated NSR pollutant.**

The following consideration should be noted:
- An emissions unit which has existed for less than 2 years from the date such emissions unit first operated is considered a new emissions unit according to 40 CFR 51.165(a)(1)(vii)(A) and, as such, the BAE shall equal the PE1 according to 40 CFR 51.165(a)(1)(xxxv)(C).

- **Projected Actual Emissions (PAE)**

PAE can be calculated in 2 ways, as discussed below.

- **PAE Determination**

  Where there is no increase in design capacity or potential to emit, the projected actual emissions (PAE) are equal to the annual emission rate at which the unit is projected to emit in any one year selected by the operator within 5 years after the unit resumes normal operation (10 years for existing units with an increase in design capacity or potential to emit).

  The source must estimate the projected actual emissions (PAE) based on all information relevant to the emission unit(s), (e.g. historical data, company's expected business activity, and highest projections of business), and provide a detailed justification of the estimate in their application. **If a justified estimate is not provided, the potential to emit (PE) for the existing emission units shall be used for this calculation**. For projects without an increase in design capacity or potential to emit, the PAE cannot exceed the pre-project potential to emit.

  - **Unused Baseline Capacity (UBC)[1]**

    As described in 40 CFR 51.165(a)(1)(xxviii)(B), when using historical data and company's expected business activity and highest projections of business activity to determine PAE, the portion of the emissions after the project that the existing unit could have accommodated before the project (**during the same 24-month baseline period used to determine BAE)** and that are unrelated to the particular project (including emissions increases due to product demand growth) are to be excluded.

    In other words, **the difference in emissions between what the unit could have actually accommodated (legally and physically) before the project and the BAE are to be subtracted from any calculated increase, if the ability to utilize the previously unused capacity is not related to the current project.** For the discussion below, this quantity is termed "Unused Baseline Capacity (UBC) emissions".

    Please note that, if a justified estimate for PAE is not provided by the applicant, the UBC can not be used in the project emissions increase calculation.

    Project emissions increase = ∑(PAE – BAE – UBC)

    Please note that to determine the UBC emissions, the facility must provide a description of all legal and physical limitations on the emission

[1] EPA guidance on UBC, more generally known as "Demand Growth Exclusion"

- Letter from U.S. EPA Region 7 to Kanas Department of Health and Environment, Re: Columbian Chemicals (December 17, 2015) - https://www.epa.gov/sites/default/files/2016-01/documents/columbian2015_0.pdf
- Letter from U.S. EPA Region 4 to Georgia Pacific (March 18, 2010) - https://www.epa.gov/sites/default/files/2015-07/documents/demandgrowth.pdf

unit's utilization rate prior to the project. Such legal and physical limitations are not limited to requirements of the District permit.

The UBC emissions can not be directly assessed as the difference between the pre-project potential to emit and the baseline actual emissions.

The UBC determinaton must be made on a case-by-case basis. In determining the UBC emissions, District staff must rely on information submited by the applicant and exercise independent judgement to assess if the claimed UBC emissions are reasonable. To determine the UBC, several factors must be considered such as the degradation of an emision unit's capacity, the ability of the unit to perform at specific capacity rate, the emission rate of the unit over time, etc. EPA has generally accepted the highest month during the 24-month baseline period extrapolated for an entire year as an acceptable quantification of the emissions the unit could have accomodated (physically).

If no information supporting the UBC emissions is provided by the applicant, UBC emissions is set to 0.

- **Otherwise, PAE = PE2**

  According to 40 CFR 51.165(a)(1)(xxviii)(B)(4), when determining PAE, in lieu of using the method described in 40 CFR 51.165 (a)(1)(xxviii)(B)(1)-(3), *Projected Actual Emissions*, the owner/operator may elect to use emissions unit's Potential to Emit.

  If appropriate projected actual emissions are not provided by the applicant, then the emissions unit's **Post-Project Potential to Emit (PE2)** is set to PAE:

  Project emissions increase = ∑(PE2 – BAE)

1.2. Calculation for New Emission Units

For new emission units, according to 40 CFR 51.165(a)(2)(ii)(D), the project's emission increase for each pollutant is the sum of the potentials to emit:

The emission increase is the post-project potential to emit. Projected actual emissions cannot be used for new emission units.

BAE are equal to 0.

Project emissions increase = ∑ (PE2)

1.3. Calculation Involving Both Modified and New Emission Units

For projects involving both existing and new emission units, the emission increase for the project is calculated as the sum of the emission increases for both the existing and new emission units.

1.4. Project Emission Increases Less than Federal Major Modification Significance Thresholds

If the project's emission increases (Step 1) are less than the Federal Major Modification significance thresholds, the project is not a Federal Major Modification and no further analysis is required.

For such projects, specific requirements apply:

- Recordkeeping of actual emission is required.
- Actual emission are required to be reported to the District if actual emissions exceed the baseline actual emissions and if the actual emissions differ from the projection of actual emissions (if utilized).
- This recordkeeping and reporting requirement remains in effect for a period of 5 years (if there is no increase in capacity) or 10 years (if there is an increase in design capcity capacity) after the modification pursuant to 51.165(a)(6).

Please note that the baseline actual emissions and projeted actual emissions are not enforecable emission limits.

Permit Condition (Example)

When the owner/operater has estimated the projected actual emissions based on all information relevant to the emission unit(s), recordkeeping and reporting requirement is shown below:

- *If the emission unit's actual emissions exceed XX,XXX lb XXX per calendar year the permittee must report to the District the annual XXX emissions as calculated pursuant to paragraph 40 CFR 51.165(a)(6)(iii) and any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection. Such information must be submitted to the District for a period of 5 calendar years beginning the year of operation under ATC X-XX-XX-X and shall be submitted within 60 days of the end of each calendar year. [District Rule 2201] Y*

2. Step 2: Net Emission Increase Calculation

If the project's emission increases are above the significance Federal Major Modification thresholds in Table 3-1, the project results in a significant emission increase and further analysis is required, except as allowed below.

Please note that, as discussed above, under the Federal Clean Air Act, section 182 (e) (2), Step 2 of the analysis shall not be performed for pollutant or their precursors

for which a district is in extreme non-attainment status. For the District this requirement applies to NOx and VOC and Step 2 of the analysis shall not be performed for these 2 criteria pollutants.

Pursuant to 40 CFR 51.165(a)(1)(vi)(A), if the project results in a significant emission increase, the creditable actual emission increases and decreases at the facility occurring during the period used to determine baseline actual emissions, within the past 5 years (including those projects not related to the subject project) must be calculated to determine if the project results in a significant net emission increase (Step 2). In this calculation, all creditable emission decreases and increases must be counted.

If the net emission increase is less than the significance thresholds, then the project is not a Federal Major Modification.

As an alternative to performing the calculation in step 2, the applicant may stipulate that the project results in both a significant emission increase and significant net emission increase. In such a case, the project constitutes a Federal major modification.

Please note that for projects that constitute a Federal Major Modification, the "amount of increased emissions" (calculated pursuant to Rule 2201 section 4.8.4.2) for such projects must be determined. Such emission increases are defined as the Federal Offset Quantity (FOQ) and discussed further in Section VII below. The resulting FOQ from each project shall be offset with internal emission reductions (IERs) or other actual emission reduction (AERs) that are surplus at the time of ATC issuance. A project is only approvable if sufficient surplus IERs and AERs are provided for the project: IERs and AERs for a project for NOx and VOC shall be provided by the applicant while IERs and AERs for PM10 and SOx may be satisfied with the reductions from the Carryover Balance or Running Balance pursuant to Rule 2201 sections 4.8.1.8 and 7.0.

VI. Rule 2201 BACT Requirement for SB 288 and Federal Major Modifications

Rule 2201 section 4.1.3 requires BACT for any new or modified emission unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification. This determination is made on a pollutant-by-pollutant basis.

In determining which emission units are new or modified, the definitions in the appropriate version of 40 CFR 51.165 shall be used, and not the definitions in Rule 2201.

Please note that, for modified emission units, only those undergoing a physical change or an actual change in the method of operation are subject to BACT requirement. Emission units not undergoing a physical change or an actual change in the method of operation are not subject to BACT requirement.

If a project results in an SB 288 or Federal Major Modification, only emission units that result in an emission increase (calculated as calculated above: PE – AE or PAE - BAE),

require BACT. If an emission unit, that is part of a project that is an SB288 or Federal Major Modification, does not result in an emission increase (calculated pursuant to the provisions in the apprporiate version of CFR 51.165) BACT is not required for that emission unit.

VII. Federal Offset Quantities

The Federal Offset Quantity (FOQ) is only calculated for the pollutants for which a project is a Federal Major Modification as determined in Section V above or a New Major Source as determined in Section lll above.

Pursuant to Rule 2201 section 4.8.4, the Federal Offset Quantity is the sum of the annual emission changes for all new and modified emission units in a project calculated as the potential to emit after the modification (PE2) minus the federal baseline emissions (FBE) for each emission unit times the applicable offset ratio. It should be noted that fugitive emissions shall be included in this calculation.

FOQ = (PE2 – FBE) x offset ratio

Pursuant to Section 3.19 of District Rule 2201, for a given pollutant, FBE = PE1 for:

- Any Highly-Utilized Emissions Unit,
- Any Fully-Offset Emissions Unit.

otherwise,

FBE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

HAE is defined in Rule 2201 section 3.26: In general, historical actual emissions as of a particular date shall equal the **average rate at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation**. The District shall allow the use of a different 24-month period upon a determination that it is more representative of normal source operation.

Please note that FBE and BAE may be different.

- FBE is the average rate at which the unit actually emitted the pollutant during a **consecutive 24-month period before the project** and which is representative of **normal source operation**,
- While BAE is calculated as the average at which the emissions unit actually emitted during **any** 24-month period selected by the operator within the previous 10-year period (5-year period for electric utility steam generating units).

Please note that for units covered by an SLC, typically there are no special calculations performed and only the emission units physically being modified are included in the Federal Offset Quantity calculation. However, if the units being modified are covered by the SLC and the PE2 would otherwise exceed the SLC, the total PE2 of all modified emission units is set equal to the post project SLC.

The federal offset ratio requirement is contained in the Federal Clean Air Act (CAA), Section 182.

According the CAA 182(e), the federal offset ratio for VOC and NOx is 1.5 to 1 (due to extreme ozone non-attainment). Otherwise the federal offset ratio for PM2.5, PM10, and SOx is 1.0 to 1. These offset ratios are contained in Rule 2201 section 4.9.

For a project that triggers Federal Major Modification requirements or results in a New Major Source, the Federal Offset Quantity shall be determined using the attached table. This table shall be included in the application review in the Federal Major Modification/Federal Offset Quantity Calculation section pursuant to APR1010. The Federal Offset Quantity shall also be entered into the Major Modification tracking database under the "Federal Offset Quantity" heading.

VII. Revisions to this Policy

Summary of 7/26/23 revisions:

- Formatting updates,
- Typographical corrections,
- Terminology clarifications,
- Clarification of treatment of fugitive emissions,
- Updates for April 20, 2023 version of Rule 2201

Federal Offset Quantity Calculations

NOx **Offset Ratio** **1.5[2]**

Permit No.	Federal Baseline Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - FBE (lb/year):	0
		Federal Offset Quantity: (PE2 – FBE) x 1.5	0

VOC **Offset Ratio** **1.5[2]**

Permit No.	Federal Baseline Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - FBE (lb/year):	0
		Federal Offset Quantity: (PE2 – FBE) x 1.5	0

PM10 **Offset Ratio** **1.0**

Permit No.	Federal Baseline Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - FBE (lb/year):	0
		Federal Offset Quantity: (PE2 – FBE) x 1.0	0

[2] The offset ratio may be 1.3 if Internal Emission Reductions are used.

PM2.5 **Offset Ratio** **1.0**

Permit No.	Federal Baseline Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - FBE (lb/year):	0
		Federal Offset Quantity: (PE2 – FBE) x 1.0	0

SOx **Offset Ratio** **1.0**

Permit No.	Federal Baseline Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - FBE (lb/year):	0
		Federal Offset Quantity: (PE2 – FBE) x 1.0	0

Appendix A
40 CFR 51.165 in effect on 12/19/02

Appendix A

40 CFR 51.165 in effect on 12/19/02
Used to determine if a project is an SB288 Major Modification

TITLE 40--PROTECTION OF ENVIRONMENT

CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY

PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS--Table of Contents

Subpart I--Review of New Sources and Modifications

Sec. 51.165 Permit requirements.

(a) State Implementation Plan provisions satisfying sections 172(b)(6) and 173 of the Act shall meet the following conditions:

(1) All such plans shall use the specific definitions. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects as the corresponding definition below:

(i) Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

(ii) Building, structure, facility, or installation means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same Major Group (i.e., which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0065 and 003-005-00176-0, respectively).

(iii) Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

(iv)(A) Major stationary source means:

(1) Any stationary source of air pollutants which emits, or has the potential to emit 100 tons per year or more of any pollutant subject to regulation under the Act, or

(2) Any physical change that would occur at a stationary source not qualifying under paragraph (a)(1)(iv)(A)(1) as a major stationary source, if the change would constitute a major stationary source by itself.

(B) A major stationary source that is major for volatile organic compounds shall be considered major for ozone

(C) The fugitive emissions of a stationary source shall not be included in determining for any of the purposes of this paragraph whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(1) Coal cleaning plants (with thermal dryers);

(2) Kraft pulp mills;

(3) Portland cement plants;

(4) Primary zinc smelters;

(5) Iron and steel mills;

(6) Primary aluminum ore reduction plants;

(7) Primary copper smelters;

(8) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(9) Hydrofluoric, sulfuric, or nitric acid plants;

(10) Petroleum refineries;

(11) Lime plants;

(12) Phosphate rock processing plants;

(13) Coke oven batteries;

(14) Sulfur recovery plants;

(15) Carbon black plants (furnace process);

(16) Primary lead smelters;

(17) Fuel conversion plants;

(18) Sintering plants;

(19) Secondary metal production plants;

(20) Chemical process plants;

(21) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(22) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(23) Taconite ore processing plants;

(24) Glass fiber processing plants;

(25) Charcoal production plants;

(26) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input; and

(27) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(v)(A) Major modification means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(B) Any net emissions increase that is considered significant for volatile organic compounds shall be considered significant for ozone.

(C) A physical change or change in the method of operation shall not include:

(1) Routine maintenance, repair and replacement;

(2) Use of an alternative fuel or raw material by reason of an order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(3) Use of an alternative fuel by reason of an order or rule section 125 of the Act;

(4) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(5) Use of an alternative fuel or raw material by a stationary source which;

(i) The source was capable of accommodating before December 21, 1976, unless such change would be prohibited under any federally enforceable permit condition which was established after December 12, 1976 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or Sec. 51.166, or

(ii) The source is approved to use under any permit issued under regulations approved pursuant to this section;

(6) An increase in the hours of operation or in the production rate, unless such change is prohibited under any federally enforceable permit condition which was established after December 21, 1976 pursuant to 40 CFR 52.21 or regulations approved pursuant to 40 CFR part 51 subpart I or 40 CFR 51.166.

(7) Any change in ownership at a stationary source.

(8) The addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the reviewing authority determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except:

(i) When the reviewing authority has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of title I, if any, and

(ii) The reviewing authority determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

(9) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) The State Implementation Plan for the State in which the project is located, and

(ii) Other requirements necessary to attain and maintain the national ambient air quality standard during the project and after it is terminated.

(vi)(A) Net emissions increase means the amount by which the sum of the following exceeds zero:

(1) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and

(2) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(B) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs before the date that the increase from the particular change occurs;

(C) An increase or decrease in actual emissions is creditable only if:

(1) It occurs within a reasonable period to be specified by the reviewing authority; and

(2) The reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section which permit is in effect when the increase in actual emissions from the particular change occurs.

(D) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(E) A decrease in actual emissions is creditable only to the extent that:

(1) The old level of actual emission or the old level of allowable emissions whichever is lower, exceeds the new level of actual emissions;

(2) It is federally enforceable at and after the time that actual construction on the particular change begins; and

(3) The reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR part 51 subpart I or the State has not relied on it in demonstrating attainment or reasonable further progress;

(4) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

(F) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

(vii) Emissions unit means any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act.

(viii) Secondary emissons means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this section, secondary emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification which causes the secondary emissions. Secondary emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction of operation of the major stationary source of major modification. Secondary emissions do not include any emissions which come directly from a mobile source such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel.

(ix) Fugitive emissions means those emissions which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening.

(x) Significant means, in reference to a net emissions increase pr the potential of a source to emit any of the following pollutions, as rate of emissions that would equal or exceed any of the following rates:

Pollutant Emission Rate

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy

(xi) Allowable emissions means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(A) The applicable standards set forth in 40 CFR part 60 or 61;

(B) Any applicable State Implementation Plan emissions limitation including those with a future compliance date; or

(C) The emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

(xii)(A) Actual emissions means the actual rate of emissions of a pollutant from an emissions unit as determined in accordance with

paragraphs (a)(1)(xii) (B) through (D) of this section.

(B) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(C) The reviewing authority may presume that the source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(D) For any emissions unit (other than an electric utility steam generating unit specified in paragraph (a)(1)(xii)(E) of this section) which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(E) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided the source owner or operator maintains and submits to the reviewing authority, on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by the reviewing authority if it determines such a period to be more representative of normal source post-change operations.

(xiii) Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following:

(A) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

(B) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within or stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.

(xiv) Federally enforceable means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR part 51, subpart I, including operating permits issued under an EPA-approved program that is incorporated into the State implementation plan and expressly requires adherence to any permit issued under such program.

(xv) Begin actual construction means in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipework, and construction of permanent storage structures. With respect

to a change in method of operating this term refers to those on-site activities other than preparatory activities which mark the initiation of the change.

(xvi) Commence as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(A) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(B) Entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(xvii) Necessary preconstruction approvals or permits means those Federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(xviii) Construction means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions.

(xix)Volatile organic compounds (VOC) is as defined in Sec. 51.100(s) of this part.

(xx) Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

(xxi) Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of
a unit, (or a different consecutive two-year period within 10 years after that change, where the reviewing authority determines that such period is more representative of source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the reviewing authority shall:

(A) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(B) Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

(xxii) Temporary clean coal technology demonstration project means a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State Implementation Plan for the State in which the project is located and

other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(xxiii) Clean coal technology means any technology, including technologies applied at the precombustion, combustion, or post combustion stage, at a new or existing facility which will achieve significant reductions in air emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of coal in the generation of electricity, or process steam which was not in widespread use as of November 15, 1990.

(xxiv) Clean coal technology demonstration project means a project using funds appropriated under the heading ``Department of Energy-Clean Coal Technology,'' up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency. The Federal contribution for a qualifying project shall be at least 20 percent of the total cost of the demonstration project.

(xxv) Pollution control project means any activity or project at an existing electric utility steam generating unit for purposes of reducing emissions from such unit. Such activities or projects are limited to:

(A) The installation of conventional or innovative pollution control technology, including but not limited to advanced flue gas desulfurization, sorbent injection for sulfur dioxide and nitrogen oxides controls and electrostatic precipitators;

(B) An activity or project to accommodate switching to a fuel which is less polluting than the fuel used prior to the activity or project, including, but not limited to natural gas or coal reburning, or the cofiring of natural gas and other fuels for the purpose of controlling emissions;

(C) A permanent clean coal technology demonstration project conducted under title II, sec. 101(d) of the Further Continuing Appropriations Act of 1985 (sec. 5903(d) of title 42 of the United States Code), or subsequent appropriations, up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency; or

(D) A permanent clean coal technology demonstration project that constitutes a repowering project.

(2) Each plan shall adopt a preconstruction review program to satisfy the requirements of sections 172(b)(6) and 173 of the Act for any area designated nonattainment for any national ambient air quality standard under 40 CFR 81.300 et seq. Such a program shall apply to any new major stationary source or major modification that is major for the pollutant for
which the area is designated nonattainment, if the stationary source or modification would locate anywhere in the designated nonattainment area.

(3)(i) Each plan shall provide that for sources and modifications subject to any preconstruction review program adopted pursuant to this subsection the baseline for determining credit for emissions reductions is the emissions limit under the applicable State Implementation Plan in effect at the time the application to construct is filed, except that the offset baseline shall be the actual emissions of the source from which offset credit is obtained where;

(A) The demonstration of reasonable further progress and attainment of ambient air quality standards is based upon the actual emissions of sources located within a designated nonattainment area for which the preconstruction review program was adopted; or

(B) The applicable State Implementation Plan does not contain an

emissions limitation for that source or source category.

(ii) The plan shall further provide that:

(A) Where the emissions limit under the applicable State Implementation Plan allows greater emissions than the potential to emit of the source, emissions offset credit will be allowed only for control below this potential;

(B) For an existing fuel combustion source, credit shall be based on the allowable emissions under the applicable State Implementation Plan for the type of fuel being burned at the time the application to construct is filed. If the existing source commits to switch to a cleaner fuel at some future date, emissions offset credit based on the allowable (or actual) emissions for the fuels involved is not acceptable, unless the permit is conditioned to require the use of a specified alternative control measure which would achieve the same degree of emissions reduction should the source switch back to a dirtier fuel at some later date. The reviewing authority should ensure that adequate long-term supplies of the new fuel are available before granting emissions offset credit for fuel switches,

(C)(1) Emissions reductions achieved by shutting down an existing source or curtailing production or operating hours below baseline levels may be generally credited if such reductions are permanent, quantifiable, and federally enforceable, and if the area has an EPA-approved attainment plan. In addition, the shutdown or curtailment is creditable only if it occurred on or after the date specified for this purpose in the plan, and if such date is on or after the date of the most recent emissions inventory used in the plan's demonstration of attainment. Where the plan does not specify a cutoff date for shutdown credits, the date of the most recent emissions inventory or attainment demonstration, as the case may be, shall apply. However, in no event may credit be given for shutdowns which occurred prior to August 7, 1977. For purposes of this paragraph, a permitting authority may choose to consider a prior shutdown or curtailment to have occurred after the date of its most recent emissions inventory, if the inventory explicitly includes as current existing emissions the emissions from such previously shutdown or curtailed sources.

(2) Such reductions may be credited in the absence of an approved attainment demonstration only if the shutdown or curtailment occurred on or after the date the new source permit application is filed, or, if the applicant can establish that the proposed new source is a replacement for the shutdown or curtailed source, and the cutoff date provisions of Sec. 51.165(a)(3)(ii)(C)(1) are observed.

(D) No emissions credit may be allowed for replacing one hydrocarbon compound with another of lesser reactivity, except for those compounds listed in Table 1 of EPA's ``Recommended Policy on Control of Volatile Organic Compounds'' (42 FR 35314, July 8, 1977; (This document is also available from Mr. Ted Creekmore, Office of Air Quality Planning and Standards, (MD-15) Research Triangle Park, NC 27711.))

(E) All emission reductions claimed as offset credit shall be federally enforceable;

(F) Procedures relating to the permissible location of offsetting emissions shall be followed which are at least as stringent as those set out in 40 CFR part 51 appendix S section IV.D.

(G) Credit for an emissions reduction can be claimed to the extent that the reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR part 51 subpart I or the State has not relied on it in demonstration attainment or reasonable further progress.

(4) Each plan may provide that the provisions of this paragraph do not apply to a source or modification that would be a major stationary source or major modification only if fugitive emission to the extent quantifiable are considered in calculating the potential to emit of the stationary source or modification and the source does not belong to any of the following categories:

(i) Coal cleaning plants (with thermal dryers);

(ii) Kraft pulp mills;

(iii) Portland cement plants;

(iv) Primary zinc smelters;

(v) Iron and steel mills;

(vi) Primary aluminum ore reduction plants;

(vii) Primary copper smelters;

(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(ix) Hydrofluoric, sulfuric, or citric acid plants;

(x) Petroleum refineries;

(xi) Lime plants;

(xii) Phosphate rock processing plants;

(xiii) Coke oven batteries;

(xiv) Sulfur recovery plants;

(xv) Carbon black plants (furnace process);

(xvi) Primary lead smelters;

(xvii) Fuel conversion plants;

(xviii) Sintering plants;

(xix) Secondary metal production plants;

(xx) Chemical process plants;

(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(xxiii) Taconite ore processing plants;

(xxiv) Glass fiber processing plants;

(xxv) Charcoal production plants;

(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(xxvii) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(5) Each plan shall include enforceable procedures to provide that:

(i) Approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provision of the plan and any other requirements under local, State or Federal law.

(ii) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforcement limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of regulations approved pursuant to this section shall apply to the source or modification as though construction had not yet commenced on the source or modification;

(b)(1) Each plan shall include a preconstruction review permit program or its equivalent to satisfy the requirements of section 110(a)(2)(D)(i) of the Act for any new major stationary source or major modification as defined in paragraphs (a)(1) (iv) and (v) of this section. Such a program shall apply to any such source or modification that would locate in any area designated as attainment or unclassifiable for any national ambient air quality standard pursuant to section 107 of

the Act, when it would cause or contribute to a violation of any national ambient air quality standard.

(2) A major source or major modification will be considered to cause or contribute to a violation of a national ambient air quality standard when such source or modification would, at a minimum, exceed the following significance levels at any locality that does not or would not meet the applicable national standard:

Pollutant	Averaging time (hours)			
	Annual	24	8	3	1
SO2	1.0 g/m\3\.	eq>g/m\3\.	eq>g/m\3\.		
PM10	1.0 g/m\3\.	eq>g/m\3\.			
NO2	1.0 g/m\3\.				
CO	.....	.....			0.5 mg/m\3\
.....	.....	2 mg/m\3\			

(3) Such a program may include a provision which allows a proposed major source or major modification subject to paragraph (b) of this section to reduce the impact of its emissions upon air quality by obtaining sufficient emission reductions to, at a minimum, compensate for its adverse ambient impact where the major source or major modification would otherwise cause or contribute to a violation of any national ambient air quality standard. The plan shall require that, in the absence of such emission reductions, the State or local agency shall deny the proposed construction.

(4) The requirements of paragraph (b) of this section shall not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant, the source or modification is located in an area designated as nonattainment pursuant to section 107 of the Act.

[51 FR 40669, Nov. 7, 1986, as amended at 52 FR 24713, July 1, 1987; 52 FR 29386, Aug 7, 1987; 54 FR 27285, 27299 June 28, 1989; 57 FR 3946, Feb. 3, 1992; 57 FR 32334, July 21, 1992]

Exhibit 8

APR 1305

San Joaquin Valley Air Pollution Control District

District Policy APR 1305
Best Available Control Technology (BACT)

Approved By:	Brian Clements Director of Permit Services	Date: June 1, 2022

I. Purpose

The purpose of this policy is to ensure that Best Available Control Technology (BACT) Determinations are made in a timely and uniform manner and in accordance with the BACT definition in District Rule 2201 - New and Modified Stationary Source Review (NSR).

II. Applicability

This policy applies to all emissions units that are subject to BACT requirements under the District's NSR Rule.

III. Definitions

A. Alternate Basic Equipment or Process

Equivalent basic equipment or process emitting less air pollutants than the basic equipment or process proposed by the applicant. This provision applies only to applications for new equipment.

B. Best Available Control Technology (BACT) - the most stringent limitation or control technique of the following:

1. Has been achieved in practice for such emissions unit and class of source; or

2. Is contained in any State Implementation Plan (SIP) approved by the Environmental Protection Agency (EPA) for such emissions unit category and class of source. (A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the APCO that such limitation or control technique is not presently achievable); or

3. Is contained in an applicable federal New Source Performance Standard; or

4. Is any other emission limitation or control technique, including alternative basic equipment or process or changes of control equipment, found by the APCO to be technologically feasible for such class or category of sources or for a specific source, and cost effective as determined by the APCO.

C. Cost Effectiveness Threshold - the threshold, above which a control alternative is not cost effective.

The District's current BACT cost effectiveness thresholds are included in Attachment A to this policy.

The cost effectiveness threshold shall be adjusted annually based on the California Consumer Price Index as compiled and reported by the Department of Industrial Relations. The threshold shall be rounded up to the nearest $100. Revised cost effectiveness thresholds will go into effect June 1st of each year. The District will present the proposed adjustment at a regularly scheduled Permit Stakeholder meeting prior to the new threshold taking effect.

If there is not a cost threshold for a pollutant for which BACT is required, the threshold for the most similar pollutant shall be utilized. For example, since ammonia is a PM_{10} precursor, the PM_{10} cost threshold would be utilized to determine the cost effectiveness of an ammonia control option.

The thresholds do not directly apply to analyses for control options that would control multiple pollutants. For options that would control more than one pollutant, a Multi Pollutant Cost Effectiveness Threshold (MCET) shall be calculated.

D. District Standard Emissions:

For new emission units, District Standard Emissions are equal to the emissions level allowed the by the applicable San Joaquin Valley Air Pollution Control District (District) rule once the final compliance date for the rule has passed. The emission limits in the applicable District prohibitory rule shall be those that the particular emission unit would be subject to. If the applicable rule has both standard and enhanced compliance options, the standard compliance option date and emission standard shall be used.

For currently permitted emission units, District Standard Emissions are equal to the emissions level allowed by the current PTO. If the rule level that the unit is currently subject to is lower than the permitted limit, the applicable rule level shall be used.

If there is no District prohibitory rule limit that applies to the new emission unit or if the existing emission unit does not have permitted emission limits, District Standard Emissions shall be set equal to commercially available emissions levels (as determined by an industry survey) for similar units. If insufficient information is available to make a determination regarding commercially available emissions levels, District Standard Emissions shall be estimated based on EPA's Compilation of Air Pollutant Emission Factors (AP-42), or other references determined by the District to be appropriate.

E. Equipment Life:

An equipment life of 10 years shall be used in cost effectiveness calculations unless a different equipment life is determined by the District to be more appropriate.

F. Interest rate:

The District's current interest rate used in BACT cost effectiveness calculations is included in Attachment A to this policy.

The interest rate used in cost effectiveness calculations shall be adjusted annually and shall be determined as follows:

1) Determine the three year moving average for the previous three years of the annual US Treasury 10-year constant maturity security interest rate
2) Add two percentage points to account for incremental risk
3) Round up the result to the next highest integer

Revised interest rate will go into effect June 1st of each year. The District will present the proposed adjustment at a regularly scheduled Permit Stakeholder meeting prior to the new rate taking effect.

G. Multi-Pollutant Cost Effectiveness Threshold (MCET):

A cost threshold calculated to determine whether an emission control alternative that would control more than one pollutant would be cost effective. Only pollutants for which BACT is triggered shall be included in the calculation. The MCET is calculated as follows:

$$\text{MCET} = \sum(\text{ton emission reduction pollutant}_i) \times (\text{cost effectiveness threshold pollutant}_i)$$

H. Technologically Feasible:

A practically applicable emission control technology or technique that, based on physical, chemical, and engineering principles, could be applied to the specific class and category of source in a commercial setting. Technologically feasible control options have not been achieved in practice.

IV. BACT Determination Cutoff Date

For emission sources that apply for an Authority to Construct prior to installation or alteration of an emissions unit, BACT Determinations are to be based upon the control technologies and methods for the same or similar source categories, listed in the District's BACT Clearinghouse on the date the application is deemed complete.

If the proposed emission source is not covered in the District's BACT Clearinghouse as of the date the application is deemed complete, then all other control technologies or methods available as of the date the application is deemed complete must be considered in determining BACT for the project.

In any case, for projects subject to the requirements of District Rule 2201, if written public comments subsequent to the District's preliminary decision identify other control technologies or methods, such technologies or methods must be considered in determining BACT prior to taking final action on the application.

V. District's BACT Clearinghouse

To assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis, the District will actively update and maintain a BACT Clearinghouse on the District’s website.

The approval of the Director of Permit Services (or designee) must be obtained prior to incorporation of new BACT requirements in permits issued by the District. Additionally, the BACT Clearinghouse must be updated for each new determination in accordance with the procedures outlined in this policy. New determinations include those made for a class or category of source not covered in the District BACT Clearinghouse and those made for control equipment or techniques not listed the District BACT Clearinghouse for a particular class or category of source.

VI. Updates to the District's BACT Clearinghouse

A. New and Revised BACT Determinations

The District will take a proactive approach to update the BACT Clearinghouse. Updates to the BACT Clearinghouse may occur when evaluating applications for new and modified sources, or when the District is made aware of and documents any of the following:

1. A new control technique or emission limitation is deemed as achieved in practice for a class or category of sources;

2. A new control technique or emission limitation is required as a part of any SIP approved by the EPA for a class or category of sources;

3. A new control technique or emission limitation is required in an applicable federal New Source Performance Standard; or

4. A new control technique or emission limitation is found to be technologically feasible for a class or category of sources.

B. Procedures for Updating the BACT Clearinghouse

Updates to the District's BACT Clearinghouse shall be made in accordance with the following procedures:

1. New or revised BACT proposals may be made by the District staff, the applicants, or the public. New or revised control technique or emission limitation are incorporated in the District's BACT Clearinghouse as the District staff review applications for new and modified sources, or as they become aware of new or revised control technique or emission limitation that are technologically feasible, achieved in practice, or incorporated in an EPA approved SIP. In order to update the District's BACT Clearinghouse, the following information must be documented:

a) Name and location of the source utilizing the control technology. Include the type of business and the size of the source. When necessary, information on the size of source should include data on the emissions unit as well as the stationary source.

b) Manufacturer and type of pollution control device.

c) Performance requirements specified under applicable permits issued by this district or any other permitting agency, or contained in an EPA approved SIP. Include the date of BACT Determination or the effective date of the new standard.

d) Available test or performance data.

e) For addition of a technologically feasible control measure, appropriate technical and engineering data to substantiate technological feasibility for the affected class and category of sources.

2. The above documentation must be forwarded to the Director of Permit Services.

3. Additional and revised Determinations will only be approved if they comply with the definition of BACT in District Rule 2201.

4. Upon approval by the Director of Permit Services (or designee), additional and revised Determinations will be posted to the District BACT clearinghouse.

VII. Determination of Achieved-in-Practice

For a control technology to be deemed as having been achieved in practice, the following conditions must be met:

- The rating and capacity for the unit where the control was achieved must be approximately the same as that for the proposed unit.

- The type of business (i.e. class of source) where the emissions units are utilized must be the same.

- The availability of resources (i.e. fuel, water) necessary for the control technology must be approximately the same.

Under the above circumstances, a control technology can be deemed as having been achieved in practice, and can be required as BACT without having to make a cost effectiveness determination.

VIII. BACT Analysis During the Preliminary Review of Applications

The primary purpose of the Preliminary Review of an application is to determine its completeness within the 30-day statutory deadline. To deem the application complete, in addition to the other necessary information, it must contain the necessary data to conduct a top-down BACT analysis, and to ensure compliance with the BACT requirements.

Ordinarily, a detailed BACT analysis will be performed as a part of the Application Review after the application is deemed complete. However, in cases where without a detailed BACT analysis, it is obvious that the proposal does not comply with the BACT requirements, the applicant must be notified of the BACT deficiencies in the form of an application incompleteness letter.

IX. Top-Down BACT Analysis

A top-down BACT analysis shall be performed as a part of the Application Review for each application subject to the BACT requirements pursuant to the District's NSR Rule. The following steps shall be documented in a top-down analysis: (For source categories or classes covered in the BACT Clearinghouse, relevant information under each of the following steps may be simply cited from the Clearinghouse without further analysis.)

A. Step 1 - Identify All Control Technologies

The first step in a top-down analysis is to identify, for the emissions unit in question, all available control options. Available control options are those air pollution control technologies or techniques, including alternate basic equipment or process with a practical potential for application to the emissions unit in question. The control alternatives should include not only existing controls for the source category in question, but also through technology transfer, controls applied to similar source categories and gas streams.

For classes and categories covered in the District's BACT Clearinghouse, the list of available control technologies shall be limited to those listed in the Clearinghouse as of the date the application is deemed complete, except when allowed pursuant to Section IV of this policy.

B. Step 2 - Eliminate Technologically Infeasible Options

In the second step, the technological feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific or emissions unit- specific factors. To exclude a control option, a demonstration of technical infeasibility must be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option for the emissions unit under review.

For classes or categories of sources covered in the District's BACT Clearinghouse, all controls listed as technologically feasible must be considered in the final BACT selection and must not be eliminated in this step.

C. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

In Step 3, all remaining control alternatives not eliminated in Step 2 must be ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A separate list should be prepared for each pollutant and for each emissions unit subject to the BACT requirement. The list should present the array of control alternatives and should indicate the effectiveness of each alternative. The list should also indicate if the alternative has been achieved in practice for the class and category of source in question.

D. Step 4 - Cost Effectiveness Analysis

After the identification of available and technologically feasible control options, economic impacts are considered to arrive at the final level of control. After performing a cost effectiveness analysis, in accordance with the procedures outlined in Section X of this policy, control options that are not cost effective, except for controls that are achieved in practice or are required by an EPA approved SIP, shall be eliminated from consideration.

Cost effectiveness analysis is not required under the following circumstances:

1. The applicant is proposing the most effective alternative in the ranking list from Step 3.

2. The most effective alternative in the ranking list from Step 3 has been achieved in practice or is required pursuant to an EPA approved SIP for the class and category of source in question.

3. Cost effectiveness analysis is not required for control alternatives which are deemed achieved-in-practice, except for achieved-in-practice alternate basic equipment or process. (A cost effectiveness analysis must always be conducted before requiring alternate basic equipment or process.)

4. Except for alternate basic equipment or process, a new cost effectiveness analysis is not required if cost effective analysis for the specific piece of equipment or operation was conducted by the District within 12 months preceding the date an application is received. A copy of the prior cost effectiveness analysis shall be attached to the Application Review, and its applicability must be documented in the Application Review.

E. Step 5 - Select BACT

The most effective control option not eliminated in Step 4 is selected as BACT for the pollutant and emissions unit under consideration, except for the following:

1. Alternate basic equipment or process shall not be required for modifications to, or transfer of location of existing equipment with valid District Permit to Operate.

2. Alternate basic equipment or process shall not be required if its use results in an increase in emissions within the District.

3. The applicant may propose to use any control technology other than the control technology required by the District if they can demonstrate that the proposed control technology can reduce air pollutant(s) as, or more, effectively than the required control technology.

X. Procedures for Conducting Cost effectiveness Analysis

A. Technologically Feasible Alternatives

1. Calculate an equivalent annual cost from a capital cost using a capital recovery factor as shown below:

$$A = P \frac{i(1+i)^n}{(1+i)^n - 1}$$ where:

A = Equivalent Annual Control Equipment Capital Cost

P = Present value of the control equipment, including installation cost

i = interest rate

n = equipment life

2. Determine annual operating cost (labor, fuel, maintenance, utilities, etc.).

3. Calculate the total annual cost by summing the equivalent annual control equipment cost and the annual operating cost (Steps 1 and 2 above).

4. Calculate the annual emission reduction as follows:

Emission reduction (ton/year) =
District Standard Emissions –
Emissions with technologically feasible BACT

5. If BACT controls only one type of air pollutant, calculate the control cost per ton of air pollutant reduced by dividing the total annual cost (Step 3) by the annual emission reduction for the air pollutant. If the control cost per ton exceeds the cost effectiveness threshold, the BACT control option is not required.

6. If a BACT option controls more than one type of air pollutant, calculate a Multi-Pollutant Cost Effectiveness Threshold (MCET) for the control option as defined above.

   If the total annual cost, (Step 3) exceeds this MCET, the control technology or equipment under review cannot be required as BACT.

7. If the control technology or equipment is not cost effective, perform the cost effectiveness analysis for the next less stringent control technology or equipment as appropriate.

B. Alternate Basic Equipment or Process:

1. Calculate the cost effectiveness of alternate basic equipment or process using the following formula:

   $CE_{alt} = (COST_{alt} - COST_{basic}) / (EMISSION_{basic} - EMISSION_{alt})$ where:

   CE_{alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

   $COST_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

   $COST_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

   $EMISSION_{basic}$ = the emissions from the proposed basic equipment, without BACT

   $EMISSION_{alt}$ = the emissions from the alternate basic equipment

XI. Enhanced Procedures to the BACT Policy

As authorized and directed by the Governing Board on August 19, 1999, the District implemented the following measures aimed at enhancing public participation and involvement in the BACT Determination process:

1. The District will hold public workshops prior to finalizing BACT Determinations that will have a potential impact on a large category for which the new determination may represent a significant change in technology,

2. The District will develop and maintain an electronic BACT Information Exchange Center. The Center will:

   a. Offer a forum for interested parties to share pertinent information on various air pollution control technologies, including feedback on operator's experience with the control technology and other related information;
   b. Provide information on new control technologies which are being proposed by facilities within the District, are under development by manufacturers, or have been approved as BACT by other agencies;
   c. Make available comments received from oversight agencies on District projects involving BACT Determinations; and
   d. Inform the public of pending new and revised BACT Determinations.

3. The District will provide a quarterly report to the Governing Board summarizing new and revised BACT Determinations for the preceding quarter.

Attachment A: *Current BACT Cost Effectiveness Thresholds and Interest Rate for District Policy APR 1305 (BACT)*

Attachment A

Current BACT Cost Effectiveness Thresholds and Interest Rate for District Policy APR 1305 (BACT)

San Joaquin Valley AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING

Memorandum

Date: June 1, 2026

To: Permit Services Department

From: Brian Clements
Director of Permit Services

Subject: Current BACT Cost Effectiveness Thresholds and Interest Rate for District Policy APR 1305 (BACT)

Beginning with the June 1, 2021 revisions to District Policy APR 1305 (BACT), the cost effectiveness thresholds and interest rate used in BACT determinations shall be adjusted annually. The revised thresholds and interest rate shall go into effect June 1st of each year.

The cost effectiveness thresholds shall be adjusted annually based on the California Consumer Price Index as compiled and reported by the Department of Industrial Relations. The threshold shall be rounded up to the nearest $100.

The following are the revised BACT cost effectiveness thresholds.

Cost Effectiveness Thresholds ($/ton):

NOx	CO	VOC	SOx	PM10/PM2.5
39,000	400	27,900	22,500	14,100

Interest Rate:

The interest rate used in cost effectiveness calculations shall be determined annually as follows:

1) Determine the three-year moving average for the previous three years of the annual US Treasury 10-year constant maturity security interest rate
2) Add two percentage points to account for incremental risk
3) Round up the result to the next highest integer

The revised interest rate used in cost effectiveness calculations is **7%**.

All applications for ATC deemed complete on and after **June 1, 2026** will be subject to the revised cost effectiveness thresholds and interest rate contained in this memorandum.

Exhibit 9

District SSP 2015

San Joaquin Valley
Air Pollution Control District

Procedures for Quantifying Fugitive VOC Emissions At Petroleum and SOCMI Facilities

Approved By: *(Signed)* Date: September 15, 2005
David Warner
Director of Permit Services

I. Purpose

The purpose of this policy is to:

1. establish the EPA and CAPCOA fugitive VOC emission factors as the generally accepted emission factors for quantifying volatile organic compound (VOC) emissions from fugitive components at petroleum and SOCMI facilities;
2. define what fugitive emissions sources are associated with permitted equipment and therefore subject to new source review accounting pursuant to Rule 2020 – Exemptions Section 6.14; and
3. define emissions unit for the purposes of assessing fugitive VOC emissions.

II. Applicability

This policy is applicable to new and modified emissions units (as defined in Rule 2201) at petroleum and SOCMI facilities that include fugitive VOC emissions sources not exempt from permit pursuant to the provisions of Rule 2020.

As used in this policy, petroleum facilities means light crude oil, heavy crude oil, or gas production operations, gas plants, refineries, or marketing terminals.

The term "component" shall have the same meaning given the term in the EPA document entitled *"Protocol for Equipment Leak Emission Estimates"* (EPA-453/R-95-017) and as further refined in the *"California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities"* (CAPCOA Guideline).

III. Background

Previously, emissions from fugitive components at petroleum and SOCMI facilities were calculated using a variety of methods including, but not limited to:

1. using emission factors in API 4322;
2. using emission factors in District policy SSP-1910 titled "Wellhead Polished Rod Packings VOC Emission Factor";
3. application of vapor control system control efficiency (CARB/KVB method) to a calculated uncontrolled emissions rate.

These methods shall no longer be used.

The approved methods for calculating fugitive emissions are those contained in EPA's "***Protocol for Equipment Leak Emission Estimate***" dated 11/95 (EPA-453/R-95-017) and "***California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities***" dated 2/99 (CAPCOA document). The CAPCOA document was developed to provide guidance to California Districts in implementing the emission factors outlined in the EPA document.

The EPA document includes emission factors for four (4) industry types:

1. oil and gas production operations
2. refineries,
3. marketing terminals, and
4. synthetic organic chemical manufacturing (SOCMI).

The emission factors for a given industry type are appropriate for use only for a facility of that same industry type.

For each industry type, there are five tiers of emission factors (listed in increasing refinement and accuracy)

1. average emission factors,
2. screening range emission factors (10,000 ppmv leak definition),
3. equations for average leak rate (ALR) emission factors for various leak definitions,
4. EPA correlation equation emission factors, and
5. unit specific correlation equation emission factors.

Note that although the ALR emission factors were not addressed in the CAPCOA document, because the CAPCOA document does not present emission factors that supercede the ALR emission factors, the ALR emission factors may be employed.

The CAPCOA document provides revisions to two sets of emission factors in the EPA document, as follows:

Table IV-2c "CAPCOA Oil and Gas Production Screening Value Range Emission Factors"

Table IV-3a “CAPCOA Refinery and Marketing Terminal Correlation Equation Emission Factors”

Additionally, a 6/11/97 letter from CAPCOA to WSPA describes the implementation of the EPA and CAPCOA emission factors for Districts in California, as follows:

Refineries and Marketing Terminals
Average emission factors can be used when there is no reliable site-specific data to use with the correlation equations. For the average emission factors, no control efficiency due to I & M will be used. Screening value range emission factors from the EPA document can be used. CAPCOA revised EPA correlation equation emission factors in CAPCOA document Table IV-3a can be used.

Oil and Gas Production Operations (Including Gas Plants)
Average emission factors can be used when there are no reliable site-specific data to use with the correlation equations. For the average emission factors, no control efficiency due to I & M will be used. CAPCOA revised screening value range emission factors in CAPCOA document Table IV-2c can be used.

Note that the concepts outlined in CAPCOA’s 6/11/97 letter were formalized in the February 1999 CAPCOA implementation guideline.

IV. District Approved Fugitive Emission Factors

Emission factors in the CAPCOA document or emission factors in the EPA document shall be used for new or modified emissions units. However, the emission factors in the CAPCOA document will take precedent over emission factors in the EPA document.

The average emission factors, screening range emission factors, equations for average leak rate emission factors for various leak definitions, EPA correlation equation emission factors, and unit-specific correlation equation emission factors may be used. The same emission factors must be used for all components associated with an emissions unit.

Any of the above generally accepted emission factors may be used for an emissions unit subject to a BACT requirement provided permit conditions are included that require periodic inspection, maintenance, and repair of leaking fugitive components.

It is preferable, though not required, to have the same calculation basis for all emissions units within a permit unit. It is permissible to have different emission factors for separate emissions units, even within a permit unit, provided the appropriate emission factors for each emissions unit are stated in the ATC/PTO.

If the screening range emission factors or ALR emission factors are used, an allowable leak fraction for an associated component type may be identified by the applicant. However, the leak fraction must comply with all other applicable requirements and the allowable leak fraction must be specified on the permit for each emissions unit.

The emission factors may be adjusted for the site-specific VOC content of the hydrocarbon vapors provided the VOC content is limited by permit conditions and periodic sampling and analysis is required.

VOC emissions are not assessed to the following components.

- Fugitive sources associated with permit exempt equipment (pursuant to Rule 2020 6.12)
- Fugitive emission components operated under vacuum, (i.e. less than atmospheric pressure of 14.7 psia). Permit conditions requiring monitoring and record keeping to verify that the components are operated under a vacuum will be required.
- For oil and gas production operations, components handling produced fluids with an API gravity less than 30°.
- For oil and gas production operations, components in water/oil service (water content greater than or equal to 50%)
- For refineries, components handling liquids with an API gravity less than 30°.
- Piping and components handling fluid streams with a VOC content of 10% or less by weight (i.e. VOCs as a percentage of the entire gas stream). Permit conditions requiring periodic monitoring and record keeping to verify the VOC content is 10% or less by weight will be required. VOC emissions may be assessed to such components if they handle significant quantities of hazard air pollutants (HAPs) as determined by the District. Please note that permittees seeking relief under this provision shall provide the District with written documentation prior to installation of components handling fluid streams with a VOC content of 10% or less by weight.
- Components that are part of field gas production pipelines/gas gathering systems (i.e. produced gas lines discharging to sales gas pipelines or gas processing plants, except for permit units and their fugitive components on such pipelines). Please note that vapor control system piping serving tanks, steam enhanced wells, separators, heater treaters, etc. are not field gas production pipelines.
- Piping and components located between petroleum production operation surface site boundaries utilized to transport material and are otherwise exempt from permit. Emissions units (e.g. IC engine/compressors, etc) that are otherwise required to have a permit are not exempt.
- Other components identified in the CAPCOA document as being not counted in estimating fugitive VOC emissions.

V. Associating fugitive emission sources with permitted emissions units pursuant to Rule 2020 6.14

Rule 2020 section 6.12 and section 6.13 provide permit exemptions for fugitive sources that are associated with emissions units that are exempt from a written permit. Emissions units that are categorically exempt from permit are those specified in Rule 2020, Sections 6.0 through section 7.0.

Rule 2020 section 6.14 states that fugitive emissions sources and pressure vessels that are associated with an emissions unit for which a written permit is required, shall be included as part of such emissions unit. A separate permit for the fugitive source or pressure vessel is not required. In determining if fugitive emissions sources are "associated" with permit exempt emissions units or are associated with emissions units that require a written permit, the following guidelines shall be used.

Please note that pressure vessels that serve as storage equipment, e.g. bullet tanks used to store natural gasoline or condensed petroleum liquids (but not including liquefied gases), require individual permits if their capacity is greater than 100 bbl. If their capacity is less then 100 bbl, they are to be listed on the permit of the associated equipment.

Notwithstanding the following, all fugitive emission sources that are part of a vapor control system, including but not limited to TEOR vapor control systems and tank vapor control systems, and all fugitive emissions sources associated with TEOR wells with closed vents or associated with TEOR well vents that tie into produced liquid piping, are not exempt from permit and are to be included with emission unit for which a written permit is required. Additionally, a source operation that vents to a vapor control system is not exempt from permit.

Note: Vapor control system (VCS) is defined as a collection and control system that collect vapors for delivery to a dedicated VOC destruction or disposal device or delivery to another gas collection system (e.g. field fuel gas system, gas production system, gas plant collection system, refinery fuel gas system, etc.). Piping and components used by a VCS for vapor collection or delivery to a gas collection system are associated with the VCS.

Fugitive emission sources are to be associated with the emissions units they serve. If fugitive emission sources are associated with an emission unit that has separate point source emissions independent of the fugitive emissions (as in the case with a heater treater that is served by a vapor control system) the aggregated fugitive emissions and point source emissions are separate emissions units. NSR requirements are determined separately for such fugitive emissions and point source emissions.

Except as provided above for vapor control systems, if a petroleum production operation surface site includes only emissions units for which a written permit is not

required, then all fugitive emissions sources at that petroleum production operation surface site are exempt from NSR requirements and permits. Conversely, if the petroleum production operation surface site includes one or more emissions units for which a permit is required, the fugitive components shall be included in the permit for the emissions unit with which they are associated.

Note: Petroleum production operation surface site means any graded pad site, gravel pad site, foundation, platform, or area where a group of equipment is installed. Petroleum production operation surface sites connected by a road, piping, or a powerline are not part of the same petroleum production operation surface site.

When an emissions unit requiring a written permit is physically removed from service or permanently disabled, the fugitive sources shall no longer be associated with that emissions unit and shall be deemed permit exempt, provided they are not associated with any other emissions unit requiring a written permit at the same petroleum production operation surface site, or are components for which VOC emissions are not assessed (as described above).

For convenience, associated fugitive emissions may be listed on the lowest numbered permit unit.

All fugitive emissions sources, including those exempt from permit, must comply with all applicable Regulation IV requirements.

Examples:

<u>Heavy oil TEOR production operations</u>

Produced fluid piping and components are exempt from permit as the API gravity is less than 30°.

When several wells are assigned to one permit, new wells may be added provided that the previously authorized well count is not exceeded in accordance with the Oilfield Permitting Policy.

For TEOR operations with a vapor control system, the entire vapor control system is one emissions unit – the well vent vapor control system emissions unit. This emissions unit includes the maximum number of wells authorized by valid ATC or PTO to be connected to the vapor control system. If the permitted well count is increased, NSR requirements shall only apply to the fugitive emissions components associated with the new wells.

For TEOR operations with closed casing vents, all wells authorized by one permit are one emissions unit. For such operations, fugitive emissions sources not on the well head are exempt from permit. For well heads designed so that

the casing annulus terminates before reaching the surface, there are no fugitive components on the well head.

If the maximum number of permitted wells is increased, NSR requirements shall only apply to the increase in permitted well count and not to the pre-addition wells.

For TEOR operations with casing vents tied into the produced fluid line, all wells authorized by one permit are one emissions unit. For such operations, fugitive components on liquid line(s) downstream of where the casing vent ties into the produced liquid line are exempt from permit.

In TEOR operations where the liquid flow line enters a vessel and the vessel discharges gas into a vapor control system (as opposed to a gas gathering system), then the vessel, (if $\leq$ 100 bbl capacity) and components are associated with the vapor control system permit. If the vessel has a capacity > 100 bbl, it requires a separate permit.

If the produced liquids are piped to a production separator and the produced gas goes to a gas gathering system (not a vapor control system), such production separator and gas gathering system piping is exempt from permit unless it is associated with an emissions unit at the same petroleum production operation surface site requiring a written permit.

Separators and piping that return the vapors immediately back to the produced liquid flow line do not require a permit.

Light oil and gas production operations

Produced liquid piping fugitive emissions components are subject to permit if the API gravity of the produced petroleum is greater than or equal to 30° and such components are associated with an emissions unit requiring a written permit at the same petroleum production operation surface site.

If the produced liquids are piped to a production separator and the produced gas goes to a gas gathering system (not a vapor control system), such production separator and gas gathering system piping is exempt from permit unless it is associated with an emissions unit requiring a written permit at the same petroleum production operation surface site.

VI. Utilizing Revised Emission Factors

Use of revised emission factors is limited to only new or modified emissions units and as allowed by District policy APR 1110. See District Policy APR 1110 Use of Revised Generally Accepted Emission Factors.

If Rule 2201 is applicable due to a modification of an emissions unit due to adding fugitive components, Rule 2201 requirements apply only to the new components. If Rule 2201 is applicable due to a modification of an emissions unit by adding to or changing the fluid handled such that permit conditions limiting the VOC content of fluid handled can no longer be met, all components handling such fluid are subject to Rule 2201 requirements.

VII. Permitting Issues

Definition of emissions unit for purposes of this policy

The following definition does not supersede the definition of emissions unit in Rule 2201. An emissions unit is an operation that results in the liberation of VOCs from process fluids, e.g. permanent separation of VOCs from process streams, including any vapor control piping up to where it connects to a shared vapor control system (which is another emissions unit). Examples include, but are not limited to, tanks, free water knockouts, production separator vessels that vent to a vapor control system, etc.

All components of a shared vapor control system downstream of the last permit unit to where the vapors are controlled by a dedicated control device, such as a flare or waste gas disposal well, are considered part of the shared vapor control system emissions unit. Should the vapors be distributed to other permitted equipment for incineration, as in the case of fuel burning equipment, or further treatment, as in the case of a natural gas processing plant, vapor control system emissions units terminate where the vapor control system piping leaves the petroleum production operation surface site. All fugitive emissions sources, including those exempt from permit, must comply with all applicable Regulation IV requirements.

Addition and/or removal of fugitive components

Addition and/or removal of fugitive emissions sources can be made without an ATC provided such change does not constitute installation of a previously unauthorized emissions unit or modification of an existing emissions unit, provided the existing daily emission limit (as calculated using current generally accepted emission factors) can continue to be complied with.

Changes for which an ATC is not required

(1) A TEOR vapor control system has a PTO that expresses the fugitive VOC emission limit using current generally accepted emission factors. Emissions from existing components are less than the DEL established at a level to provide operation flexibility. The permittee proposes to install a new fin fan cooler in the vapor control system, including several new fugitive components. The increase in fugitive emissions can be accommodated in the existing DEL. As this change does not constitute a change in the method of operation of the TEOR vapor control

system or include the installation of new emissions units, it can be made without an ATC provided the record of the count of components actually installed is maintained current.

(2) The operation of several wells included in the authorized well count are discontinued resulting in several empty “well slots”. The well slots may be filled with other wells provided the total well count is not exceeded.

(3) A vapor control system has a PTO. The operator proposes in an ATC application to add a permit condition limiting the VOC content of the vapor in the vapor collection system to less than 10% by weight with requirements for periodic sampling. After the ATC is issued and converted to a PTO the operator may add, remove, or replace components on the vapor control system without obtaining an ATC provided the record of the count of components actually installed is maintained current.

Changes for which an ATC is required

(1) A TEOR vapor control system has a PTO that does not specify the fugitive VOC emission limit using current generally accepted emission factors. The permittee proposes to install a new fin fan cooler in the vapor control system, including several new fugitive components. Because the existing PTO does not establish a DEL based on generally accepted emission factors, the permittee must provide an estimate of the number and type of existing fugitive components to establish the pre-project DEL. As the addition of the new fugitive components will result in an increase in emissions assessed to the emissions unit, an ATC is required. Such an ATC is subject to New Source Review.

(2) Installing a new tank > 100 bbl capacity and connecting it to an existing vapor control system. The new tank is a new emissions unit and an ATC is required. Such an ATC is subject to New Source Review. The existing vapor control system permit must be revised to indicate that it now serves the new tank, therefore an ATC is required. Provided there are no changes required to the vapor control system that will result in a change to the method of operation and there is no physical change to the vapor control system or disposal device(s) other than the connection of the new tank vapor control piping to the vapor control system, the ATC to modify the VCS permit unit is not subject to NSR.

Establishing fugitive components to provide operational flexibility

In order to provide for construction uncertainties and/or addition or removal of fugitive emission sources (provided such change does not include a new emissions unit or modify, as defined in Rule 2201, an existing emissions unit) a permittee may establish a fugitive emission limit at up to 120% of expected fugitive emissions. Notwithstanding this provision to provide for construction/operational flexibility, only

the emissions calculated on the fugitive components actually installed may be considered when a permitting action involves reducing fugitive emissions.

Subsequent addition or removal of fugitive emissions sources (provided such change does not include a new emissions unit or modify, as defined in Rule 2201, an existing emissions unit) may be made without an ATC. The permittee shall be required to maintain accurate records of the number, type, and calculated emissions for the components actually installed and update such records when new fugitive emission sources are installed, removed, or replaced. All fugitive components shall be subject to all permit requirements, including inspection, maintenance, and record keeping.

Any permit or rule requirements that limit the percentage of leaking components shall be based on the total number of components actually installed, not on the number of permitted components.

Petroleum facility tanks

Each tank connected to vapor control is a separate emissions unit.

Steam-enhanced and in-situ combustion wells

When implementing Policy APR 1110, Use of Revised Generally Accepted Emission Factors, the pre-project emissions for the wells are to be based on the maximum number of fugitive components associated with the wells actually installed plus the number of fugitive components associated with the additional wells authorized by any valid ATC.

Throughput and true vapor pressure of liquids stored in tanks

Regardless of the method used to ascertain the emission rate from tanks with vapor control, when applications to modify organic liquid storage tanks are submitted the District may require information on the service, throughput, and true vapor pressure of liquids stored in tanks. While this information generally will not be specified on the permit, it may be used to determine when proposed changes at a stationary source result in a NSR Modification due a change in the method of operation.

Expression of a daily emission limit (DEL) for emissions from fugitive components on ATCs/PTOs

The DEL for an emissions unit may be expressed directly as a lb/day limit or indirectly as a combination of a component count for each component type, emission factors for each component type, and a maximum number of leaking components.

For components for which VOC emissions are not assessed (as described above) the permit must contain conditions that enforce the basis for excluding the components from emission calculations. A DEL of 0.0 lb/day shall not be included for such components.

Emissions from some or all of the emissions units within a permit unit may be expressed as one or more DEL(s). However, in some cases, a DEL for each new or modified emissions unit may be required.

Each permit must contain one or more DEL(s) that limit the NSR authorized emissions from that permit unit.

Exhibit 10

District Inspection Reports

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT
COMPLIANCE INSPECTION SUMMARY

INSPECTION TYPE: ☒ COMPLIANCE ☐ VARIANCE ☐ BREAKDOWN ☐ OTHER:

SOURCE NAME: KERN ENERGY EPA DESIGNATION: TITLE V

LOCATION: PANAMA LN & WEEDPATCH HWY CITY: BAKERSFIELD FID#: S-37

CONTACT & TITLE: GABE CASTRO PHONE: 661-845-0761 EMAIL: GCASTRO@KERNENERGY.COM

INSPECTION DATE: 11/6/24, 11/12/24, 11/13/24,11/14/24, 11/20/24,11/25/24, 12/3/24, 12/5/24, 12/17/24,12/19/24, 1/6/25 INSPECTOR(s): CRISTELA AVALOS

ACCOMPANIED BY: K. BORN, J.GONZALEZ, K. BLOMBERG, E. WOODS, K. TROUNG, K. RUSSELL JOINT INSPECTION REQUIRED WITH:

HEALTHY AIR LIVING CONTACT: TITLE: PHONE:

INSPECTED EQUIPMENT				OPERATING		COMPLIANCE		
PERMIT UNIT	ATC	C/O	EQUIPMENT DESCRIPTION *SELECT ALL:*	YES: OP, SB	NO: DEU, OOS, ABND	YES: Y	NO: N	ALT. FREQ: ALL
S-37-0-4	☐	☐	Facility-Wide Requirements			☐	☐	☐
S-37-1-18	☐	☐	120 MMBTU/HR CRUDE UNIT INCLUDING ONE DESALTER, 4 FRACTIONATION VESSELS, STRIPPER, 2 ACCUMULATORS, LIGHT NAPHTHA STABILIZER, KNOCKOUT DRUM SCRUBBER, 60 MMBTU/HR TULSA HEATERS INC. PROCESS HEATER WITH CLEARSIGN MODEL CORE LOW NOX BURNERS, 60 MMBTU/HR BORN HEATER WITH CLEARSIGN MODEL CORE LOW NOX BURNERS, AND 35 HEAT EXCHANGERS	OP		☒	☐	☐
S-37-2-10	☐	☐	RERUN UNIT INCLUDING PRE-FLASH DRUM, FRACTIONATOR, STRIPPER, ACCUMULATOR, AND ASSOCIATED VALVES, FLANGES, AND CONNECTORS		OOS	☒	☐	☐
S-37-3-11	☐	☐	KEROSENE HYDROTREATER UNIT (KHT) INCLUDING A SPLITTER, A REACTOR, A SEPARATOR, 3 ACCUMULATORS, 11.4 MMBTU/HR CHARGE HEATER WITH ZEECO GLSF-10 LOW NOX BURNERS AND 12.5 MMBTU/HR SPLITTER REBOILER HEATER WITH ZEECO GLSF-10 LOW NOX BURNERS AND COMPRESSOR POWERED BY IC ENGINE S-37-163	OP		☒	☐	☐
S-37-4-20	☐	☐	PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSORS	OP		☐	☒	☐
S-37-5-4	☐	☐	LIQUID-LIQUID MEROX SWEETENING UNIT INCLUDING MIXER, CAUSTIC SETTLER, CATALYST INJECTION PORT, AND ASSOCIATED PUMPS AND PIPING	OP		☐	☒	☐
S-37-6-20	☐	☐	49.0 MMBTU/HR COEN, MODEL #D-57, DUAL-FIRED INDUCED DRAFT WATER TUBE BOILER #6 - REPLACEMENT STANDBY BOILER FOR THE TURBINE AND/OR DUCT BURNER (COGENERATION UNIT S-37-114)		OOS	☐	☒	☐
S-37-7-8	☒	☒	MODIFICATION OF JOHN ZINK STF-S-8 STEAM ASSIST FLARE WITH CONSTANT IGNITION PILOTS, INCLUDING THE FOLLOWING GAS RECOVERY EQUIPMENT: TWO ELECTRIC DRIVEN GAS COMPRESSORS (350 HP TOTAL), FOUR KNOCKOUT POTS, ONE SEAL POT, TWO HEAT EXCHANGERS, TWO STEAM DRIVEN LIQUID RECOVERY PUMPS, AND ONE ELECTRIC DRIVEN LIQUID RECOVERY PUMP (2 HP), C-02 COMPRESSOR SKID INCLUDING ONE COMPRESSOR (250 HP), TWO KNOCKOUT POTS AND A HEAT EXCHANGER: REPLACE COMPRESSOR SKID C-01 AND ADJUST THE FUGITIVE COMPONENT VOC EMISSION LIMIT TO REFLECT COMPRESSOR SKIDS C-02 AND C-03 AS-BUILT EMISSIONS	OP		☒	☐	☐
S-37-7-10	☒	☐	JOHN ZINK STF-S-8 STEAM ASSIST FLARE WITH CONSTANT IGNITION PILOTS, INCLUDING THE FOLLOWING GAS RECOVERY EQUIPMENT: TWO ELECTRIC DRIVEN GAS COMPRESSORS (350 HP TOTAL), FOUR KNOCKOUT POTS, ONE SEAL POT, TWO HEAT EXCHANGERS, TWO STEAM DRIVEN LIQUID RECOVERY PUMPS, AND ONE ELECTRIC DRIVEN LIQUID RECOVERY PUMP (2 HP), C-02 COMPRESSOR SKID INCLUDING: COMPRESSOR (250 HP), TWO KNOCKOUT POTS AND A HEAT EXCHANGER			☐	☐	☐
S-37-7-11	☒	☐	MODIFICATION OF JOHN ZINK STF-S-8 STEAM ASSIST FLARE WITH CONSTANT IGNITION PILOTS, INCLUDING THE FOLLOWING GAS RECOVERY EQUIPMENT: THREE ELECTRIC DRIVEN GAS COMPRESSORS C-03, C-02 AND C-04 (250 HP EACH), EIGHT KNOCKOUT POTS, ONE SEAL POT, TWO HEAT EXCHANGERS, TWO STEAM DRIVEN LIQUID RECOVERY PUMPS, AND THREE ELECTRIC DRIVEN LIQUID RECOVERY PUMP (2 HP): REPLACE TWO STEAM DRIVEN PUMPS WITH TWO ELECTRIC DRIVEN PUMPS (10 HP EACH) AND ADJUST FUGITIVE COMPONENT COUNT			☐	☐	☐
S-37-8-38	☐	☐	ORGANIC LIQUID LOADING AREAS AND REFINERY VAPOR RECOVERY SYSTEM SERVING ORGANIC LIQUID STORAGE TANKS, COMPRESSOR(S), AND LOADING RACKS (RACKS A, F, K, L, N) WITH 10 PRODUCT LINES AND 9 VAPOR RETURN LINES	OP		☐	☒	☐

S-37-9-13	☐	☐	OIL/WATER SEPARATION OPERATION INCLUDING CORRUGATED PLATE SEPARATOR (DORMANT), INDUCED AIR FLOATATION UNIT, DRAIN PIT, FOUR FILTERS, AND THREE 5,000 BBL STORAGE TANKS (#5061, 5062, AND 5063)	OP		☒	☐	☐
S-37-12-4	☐	☐	210,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #5009 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-13-4	☐	☐	210,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #5010 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-14-4	☐	☐	210,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #5011 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-15-5	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5020 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-16-7	☐	☐	504,000 GALLON FIXED ROOF TANK CONNECTED TO VAPOR CONTROL SYSTEM S-37-8	OP		☒	☐	☐
S-37-18-4	☐	☐	420,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #10007 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-19-4	☐	☐	420,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #10008 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-20-5	☐	☐	420,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #10001 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-21-12	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5006	OP		☒	☐	☐
S-37-22-12	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5007	OP		☒	☐	☐
S-37-23-9	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5008 SERVED BY REFINERY SHARED VAPOR RECOVERY SYSTEM LISTED ON S-37-8	OP		☒	☐	☐
S-37-24-6	☐	☐	126,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #3014 SERVED BY VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-25-5	☐	☐	126,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #3026	OP		☒	☐	☐
S-37-26-5	☐	☐	126,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #3027	OP		☒	☐	☐
S-37-27-6	☐	☐	37,000 BBL (ALTECH INDUSTRIES) INTERNAL FLOATING ROOF CRUDE OIL STORAGE TANK (#37,000), RIVETED CONSTRUCTION WITH MECHANICAL SHOE PRIMARY SEAL AND RIM-MOUNTED SECONDARY SEAL	OP		☒	☐	☐
S-37-28-6	☐	☐	80,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#80000) VENTED TO VAPOR RECOVERY SYSTEM LISTED ON TANK S-37-130	OP		☒	☐	☐
S-37-31-8	☐	☐	1,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#1000) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-34-7	☐	☐	80,000 BBL EXTERNAL FLOATING ROOF PETROLEUM STORAGE TANK (#80,001), WELDED CONSTRUCTION WITH METALLIC SHOE PRIMARY SEAL AND SECONDARY RIM-MOUNTED SEAL	OP		☒	☐	☐
S-37-38-13	☐	☐	TRANSMIX UNIT INCLUDING DISTILLATION COLUMNS, CONDENSERS, DRUMS, EXCHANGERS, PUMPS, REBOILERS, 3.75 MMBTU/HR GAS-FIRED FIRE TUBE HEATER (H-1), 3.67 MMBTU/HR GAS-FIRED HEATER (H-2) AND ASSOCIATED PIPING AND COMPONENTS	OP		☐	☒	☐
S-37-42-5	☐	☐	3,600 BBL ORGANIC LIQUID STORAGE TANK (#3300) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-43-5	☐	☐	15 HP LIGHT SOLVENT TRUCK LOADING OPERATION WITH VAPOR CONTROL SYSTEM INCLUDING: EMCO WHEATON LOADING HOSE AND VAPOR RETURN COUPLERS, 15 PUMP, METER AND CHECK VALVES AND VAPOR RETURN PIPING TO VAPOR CONTROL SYSTEM (RACK G)	OP		☒	☐	☐
S-37-44-6	☐	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3019)	OP		☒	☐	☐
S-37-46-7	☐	☐	30 HP LIQUID LOADING/UNLOADING OPERATION INCLUDING ONE UNCONTROLLED LIQUID LOADOUT LINE, ONE ORGANIC LIQUID LOADOUT/UNLOAD (TRANSFER) LINE EQUIPPED WITH VAPOR RECOVERY, TWO 15 HP PUMPS, DRY-BREAK CONNECTORS, METER(S), AND CHECK VALVES (RACK Q)	OP		☒	☐	☐
S-37-48-5	☐	☐	5,400 BBL ORGANIC LIQUID STORAGE TANK (#5014) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)		OOS	☒	☐	☐
S-37-49-5	☐	☐	5,400 BBL ORGANIC LIQUID STORAGE TANK (#5015) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-50-6	☐	☐	1,000 BBL ORGANIC LIQUID STORAGE TANK (#1100) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-51-6	☐	☐	20,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#20001) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-52-7	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10000) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	SB		☒	☐	☐
S-37-53-6	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10002) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-56-5	☐	☐	500 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#505) WITH A SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT UNIT S-37-8	OP		☒	☐	☐
S-37-57-8	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5017 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8 AND 29 HP CIRCULATION PUMP WITH CLAY FILTER	OP		☒	☐	☐
S-37-58-4	☐	☐	29 HP JP-4 TRUCK LOADING OPERATION INCLUDING TWO EMCO WHEATON API STYLE DRYBREAK BOTTOM LOADING COUPLERS AND HOSES, TWO OPW MODEL 633 VAPOR RECOVERY COUPLERS AND VAPOR RETURN HOSES, 29 HP UNLOADING PUMP, FILTER, AND METER AND CHECK VALVES (RACK H)	OP		☒	☐	☐
S-37-59-6	☐	☐	20,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#20000) WITH A SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT UNIT S-37-8	OP		☒	☐	☐

S-37-61-8	☐	☐	800 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#800) WITH A SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT UNIT S-37-8	OP		☒	☐	☐
S-37-65-6	☐	☐	250 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#250, DEHY NORTH) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-66-6	☐	☐	250 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#251, DEHY SOUTH) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-67-5	☐	☐	8,400 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#200) WITH VAREC P/R VALVE, 1 HP PUMP, AND TRUCK UNLOADING FILL LINE WITH DRY-BREAK COUPLER (RACK T)		OOS	☒	☐	☐
S-37-71-7	☐	☐	ORGANIC LIQUID TRUCK LOADING/UNLOADING OPERATION INCLUDING TRUCK UNLOADING CONNECTION, TRUCK LOADING HOSE WITH DRY BREAK COUPLER, VAPOR RECOVERY HOSE WITH DRY BREAK CONNECTOR AND PIPING TO PERMITTED TANKS S-37-50 AND S-37-56 (RACK E)	OP		☒	☐	☐
S-37-77-21	☐	☐	36 MMBTU/HR DIESEL HYDROTREATER UNIT INCLUDING A 18 MMBTU/HR CHARGE HEATER WITH ZEECO INCORPORATED MODEL GLSF-11 FREE JET BURNERS, 18 MMBTU/HR STRIPPER HEATER WITH A CALLIDUS LE-CSG LOW NOX BURNER, HYDROGEN REACTOR VESSEL, HYDROGEN RECYCLE GAS SCRUBBER, AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSOR	OP		☐	☒	☐
S-37-78-5	☐	☐	SULFUR SCRUBBING SYSTEM INCLUDING MEA/DEA CONTACTOR VESSEL (ABSORBER), GAS LIQUID SEPARATOR, AMINE REGENERATION VESSEL, LIQUID SOLID SEPARATOR, SULFUR FILTER, AND ASSOCIATED AIR BLOWERS, PUMPS AND PIPING	OP		☒	☐	☐
S-37-79-5	☐	☐	14,700 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#335) CONNECTED TO VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-80-4	☐	☐	471 BHP DETROIT MODEL 12V71T DIESEL FIRED IC ENGINE DRIVING AN EMERGENCY GENERATOR	SB		☒	☐	☐
S-37-81-4	☐	☐	225 HP CUMMINS MODEL NT855F1 DIESEL FIRED IC ENGINE DRIVING AN EMERGENCY FIREWATER PUMP	OP		☒	☐	☐
S-37-82-5	☐	☐	60 BHP WAUKESHA MODEL 135 GZU-15861-G GAS-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN INSTRUMENT AIR COMPRESSOR		OOS	☒	☐	☐
S-37-83-5	☐	☐	150 BHP WAUKESHA MODEL 6 WAKB-10F GAS-FIRED EMERGENCY STANDBY IC ENGINE POWERING A UTILITY AIR COMPRESSOR	SB		☒	☐	☐
S-37-90-6	☐	☐	2,500 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#2501) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-91-7	☐	☐	2,500 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#2502) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-93-5	☐	☐	TRUCK LOADING RACK (RACK C), INCLUDING 6 ORGANIC LIQUID LOADING SPOTS	OP		☒	☐	☐
S-37-94-8	☐	☐	RAILCAR LIQUID TRANSFER FACILITY INCLUDING 48 ORGANIC LIQUID TRANSFER HOSES, 6 BUTANE TRANSFER HOSES, 8 TRANSFER PUMPS, AND 1 TRANSFER COMPRESSOR (RACK W)	OP		☐	☒	☐
S-37-95-9	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10003) VENTING TO A 2,000 LB CARBON CANISTER (SHARED WITH PERMIT UNIT S-37-96)		OOS	☒	☐	☐
S-37-96-8	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10004) VENTING TO A 2,000 LB CARBON CANISTER (SHARED WITH PERMIT UNIT S-37-95)		OOS	☒	☐	☐
S-37-97-6	☐	☐	3,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#3012) WITH A VAPOR CONTROL SYSTEM (LISTED ON PERMIT UNIT S-37-8)		OOS	☒	☐	☐
S-37-102-7	☐	☐	10,000 BBL (420,000 GALLON) FIXED ROOF ORGANIC LIQUID STORAGE TANK #10005 SERVED BY VAPOR CONTROL SYSTEM LISTED ON PTO S-37-8	OP		☒	☐	☐
S-37-107-5	☐	☐	LPG, NATURAL GASOLINE, & MIXED LIGHT HYDROCARBON LOADING/UNLOADING RACK (RACK V) WITH VAPOR COLLECTION SYSTEM SERVING TANKS S-37-108 & -109	OP		☐	☒	☐
S-37-108-4	☐	☐	5,000 BBL SPHERICAL PRESSURE VESSEL STORING LPG, NATURAL GASOLINE, OR MIXED LIGHT HYDROCARBONS (TANK S-5000, EAST SPHERE)	OP		☐	☒	☐
S-37-109-4	☐	☐	5,000 BBL SPHERICAL PRESSURE VESSEL STORING LPG, NATURAL GASOLINE, OR MIXED LIGHT HYDROCARBONS (TANK S-5001, WEST SPHERE)	OP		☒	☐	☐
S-37-111-9	☐	☐	55,000 BBL ORGANIC LIQUID INTERNAL FLOATING ROOF TANK (#55000), WELDED CONSTRUCTION WITH MECHANICAL SHOE PRIMARY SEAL AND RIM-MOUNTED SECONDARY SEAL	OP		☒	☐	☐
S-37-114-8	☐	☐	SOLAR TARUS 60-7901S COGENERATION SYSTEM WITH NATURAL GAS FIRED TURBINE WITH DRY LOW NOX COMBUSTORS POWERING A 5.5 MEGAWATT ELECTRICAL GENERATOR, 23 MMBTU/HR NATURAL GAS FIRED DUCT BURNER, HEAT RECOVERY STEAM GENERATOR, SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND OXIDATION CATALYST	OP		☒	☐	☐
S-37-116-7	☐	☐	14.1 MMBTU/HR SPLITTER REBOILER HEATER SERVING PERMIT UNIT S-37-4	OP		☒	☐	☐
S-37-118-6	☐	☐	NAPHTHA FEED PRETREATMENT UNIT (NAPHTHA HYDROTREATER) WITH 12.6 MMBTU/HR CHARGE HEATER WITH JOHN ZINK COOLSTAR LOW NOX BURNER, 11.1 MMBTU/HR STRIPPER REBOILER HEATER WITH JOHN ZINK COOLSTAR LOW NOX BURNER, REACTOR VESSEL, HYDROGEN COMPRESSORS, HEAT EXCHANGERS, AND ASSOCIATED SEPARATOR VESSELS, KNOCKOUTS, PIPING, AND COMPONENTS AND COMPRESSOR POWERED BY IC ENGINE S-37-164	OP		☐	☒	☐
S-37-119-8	☐	☐	MODIFICATION OF NAPHTHA REFORMER UNIT WITH 25.7 MMBTU/HR CHARGE HEATER #1 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 13.4 MMBTU/HR CHARGE HEATER #2 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 8.9 MMBTU/HR CHARGE HEATER #3 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 8.3 MMBTU/HR SPLITTER/STABILIZER HEATER WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, REACTOR VESSELS, HYDROGEN COMPRESSORS, HEAT EXCHANGERS, AND ASSOCIATED SEPARATOR VESSELS, KNOCKOUTS, PIPING, AND COMPONENTS: REPLACE ONE STEAM DRIVEN COMPRESSOR WITH ONE ELECTRIC COMPRESSOR AND ONE ELECTRIC COMPRESSOR WITH ONE IC ENGINE DRIVEN COMPRESSOR S-37-165	OP		☐	☒	☐
S-37-120-4	☐	☐	AMINE SYSTEM WITH ABSORBER VESSELS, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS. TREATED VAPOR RECOVERY GAS USED AS FUEL GAS FOR PROCESS HEATERS OR FLARED IN S-37-7	OP		☒	☐	☐

S-37-121-5	☐	☐	SOUR WATER SYSTEM WITH TWO STRIPPER COLUMNS, STEAM REBOILER, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS	OP		☒	☐	☐
S-37-122-8	☐	☐	CLAUS PROCESS SULFUR RECOVERY UNIT WITH REACTION FURNACE, THREE CONVERTER VESSELS, HYDROGENATION REACTOR, ENCLOSED SULFUR PIT WITH EDUCTOR VENT TO SULFUR PLANT, TAIL GAS TREATMENT UNIT INCLUDING AMINE SCRUBBING SYSTEM AND 2.5 MMBTU/HR INCINERATOR WITH JOHN ZINK VYD BURNER OR EQUIVALENT, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS	OP		☒	☐	☐
S-37-123-4	☐	☐	481 HP CATERPILLAR DIESEL-FIRED EMERGENCY IC ENGINE MODEL 3408DITA POWERING AN EMERGENCY FIREWATER PUMP	SB		☒	☐	☐
S-37-125-4	☐	☐	3,000 BBL (126,000 GALLON) FIXED ROOF ORGANIC LIQUID STORAGE TANK, #3013, SERVED BY THE VAPOR CONTROL SYSTEM OPERATING UNDER PERMIT S-37-8	OP		☒	☐	☐
S-37-126-4	☐	☐	55,000 BBL ORGANIC LIQUID STORAGE TANK #55002 WITH VAPOR BALANCE RETURN LINE FROM ORGANIC LIQUID LOADING RACK VAPOR RETURN PIPING AND VENTED TO VAPOR CONTROL SYSTEM LISTED ON S-37-8	OP		☒	☐	☐
S-37-127-5	☐	☐	GASOLINE DISPENSING OPERATION WITH ONE 12,000 SPLIT (9,000 GALLONS GASOLINE/3,000 GALLONS DIESEL) STEEL TANK INSTITUTE FIREGUARD ABOVEGROUND STORAGE TANK SERVED BY OPW PHASE I ENHANCED VAPOR RECOVERY (EVR) SYSTEM (VR-401-C), STANDING LOSS CONTROL (VR-301-E), AND 1 FUELING POINT WITH 1 GASOLINE DISPENSING NOZZLE SERVED BY BALANCE PHASE II VAPOR RECOVERY SYSTEM (G-70-162-A)	OP		☒	☐	☐
S-37-130-6	☐	☐	MODIFICATION OF 74,000 BBL INTERNAL FLOATING ROOF ORGANIC LIQUID STORAGE TANK, WELDED CONSTRUCTION WITH METALLIC SHOE PRIMARY SEAL AND WIPER SECONDARY SEAL (TANK #74000): CONVERT TO FIXED ROOF AND CONNECT TO VAPOR RECOVERY SYSTEM	OP		☐	☒	☐
S-37-131-4	☐	☐	74,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#74001) VENTED TO VAPOR RECOVERY SYSTEM LISTED ON TANK S-37-130	OP		☒	☐	☐
S-37-138-4	☐	☐	ORGANIC LIQUID TRANSFER FACILITY WITH FOUR TRANSFER RACKS (RACK X)	OP		☒	☐	☐
S-37-139-4	☐	☐	CRUDE OIL UNLOADING RACK (NORTH OF TANK #80000) WITH TWO UNLOADING STATIONS, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS - LANE 1 SOUTH (RACK AA)	OP		☐	☒	☐
S-37-140-4	☐	☐	CRUDE OIL UNLOADING RACK (NORTH OF TANK #80000) WITH TWO UNLOADING STATIONS, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS - LANE 2 MIDDLE (RACK AA)	OP		☒	☐	☐
S-37-141-4	☐	☐	ORGANIC LIQUID UNLOADING RACK NORTH OF TANK #80000 WITH TWO UNLOADING HOSES, TRANSFER PUMP, AND ASSOCIATED VALVES, FLANGES, AND THREADED CONNECTIONS - LANE 3 NORTH (RACK AA)	OP		☐	☐	☐
S-37-142-4	☐	☐	RESIDUAL OIL TRANSFER RACK (FROM TRUCKS TO REFINERY OR REVERSE) EAST OF TANK #10000, WITH TWO TRANSFER POINTS, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS (RACK U)	OP		☒	☐	☐
S-37-143-4	☐	☐	RESIDUAL OIL TRANSFER RACK (FROM TRUCKS TO REFINERY OR REVERSE) NORTHWEST OF TANK #10006, WITH ONE TRANSFER POINT, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS (RACK Y)	OP		☒	☐	☐
S-37-147-2	☐	☐	ORGANIC LIQUID UNLOADING RACK (RACK S) - SOUTH OF DIESEL TANK FARM	OP		☒	☐	☐
S-37-148-2	☐	☐	54,000 BBL EXTERNAL FLOATING ROOF ORGANIC LIQUID STORAGE TANK WITH EITHER A DUAL WIPER SEAL WITH DRIP CURTAIN OR PRIMARY METAL SHOE SEAL WITH SECONDARY WIPER SEAL	OP		☒	☐	☐
S-37-149-3	☐	☐	4 MMSCF/DAY LPG RECOVERY UNIT INCLUDING GAS COMPRESSION, MEMBRANE SEPARATION, REFRIGERATION, SOLID PHASE DRYING/ DEHYDRATION, AND FRACTIONATION	OP		☒	☐	☐
S-37-150-2	☐	☐	3000 BBL ORGANIC LIQUID STORAGE TANK VENTED TO VAPOR CONTROL SYSTEM LISTED ON S-37-8	OP		☒	☐	☐
S-37-153-1	☐	☐	16,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (ID 16005) SERVED BY VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-154-1	☐	☐	16,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (16006) SERVED BY VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-155-1	☐	☐	ORGANIC LIQUID TRANSFER RACK R	OP		☒	☐	☐
S-37-157-1	☐	☐	240 HP WAUKESHA MODEL MODEL F18G, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) DRIVING RECYCLE COMPRESSOR UNIT SERVING THE DIESEL HYDROTREATER (S-37-37)	OP		☒	☐	☐
S-37-158-1	☐	☐	27.6 MMBTU/HR CLEAVER BROOKS MODEL CBLE 700-800-250ST NATURAL GAS-FIRED FORCED AIR BOILER WITH A CLEAVER BROOKS ULTRA LOW NOX BURNER	OP		☒	☐	☐
S-37-159-1	☐	☐	310 HP WAUKESHA MODEL F18SE NATURAL GAS-FIRED IC ENGINE WITH NON-SELECTIVE CATALYTIC REDUCTION SERVING THE NORTH HYDROGEN COMPRESSOR AT THE PLATFORMER UNIT (S-37-4)	SB		☒	☐	☐
S-37-160-1	☐	☐	310 HP WAUKESHA MODEL F18SE NATURAL GAS-FIRED IC ENGINE WITH NON-SELECTIVE CATALYTIC REDUCTION SERVING THE #1 HYDROGEN COMPRESSOR- SOUTH, AT THE PLATFORMER UNIT (S-37-4)	OP		☒	☐	☐
S-37-161-1	☐	☐	310 HP WAUKESHA MODEL F18SE NATURAL GAS-FIRED IC ENGINE WITH NON-SELECTIVE CATALYTIC REDUCTION SERVING THE WEST HYDROGEN COMPRESSOR AT THE UNIFIER UNIT (S-37-3)	OP		☒	☐	☐
S-37-163-1	☐	☐	310 HP WAUKESHA MODEL MODEL F18SE, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) SERVING THE EAST HYDROGEN COMPRESSOR AT THE KHT UNIT (#S-37-3)	SB		☒	☐	☐

S-37-164-1	☐	☐	310 HP WAUKESHA MODEL MODEL F18SE, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) SERVING NAPHTHA HYDROTREATER RECYCLE COMPRESSOR (#S-37-118)	OP		☒	☐	☐
S-37-165-1	☐	☐	310 HP WAUKESHA MODEL MODEL F18SE, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) SERVING NAPHTHA REFORMER RECYCLE COMPRESSOR (#S-37-118)	OP		☐	☒	☐
S-37-169-0	☐	☐	AMINE SYSTEM NO.2 WITH ABSORBER VESSELS, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS WITH TREATED VAPOR RECOVERY GAS USED AS FUEL GAS FOR PROCESS HEATERS OR FLARED IN S-37-7	OP		☒	☐	☐
S-37-171-0	☒	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3016) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8).	OP		☐	☒	☐
S-37-172-0	☒	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3017) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8).	OP		☐	☒	☐
S-37-173-0	☒	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3018) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8).		OOS	☒	☐	☐
S-37-174-1	☐	☐	504,000 GALLON FIXED ROOF TANK (#12001) WITH VAPOR CONTROL SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-175-0	☒	☒	5,000 BBL ORGANIC LIQUID STORAGE TANK (#5013) SERVED BY SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-176-0	☒	☐	3,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#3012) SERVED BY VAPOR CONTROL SYSTEM LISTED ON PERMIT UNIT S-37-8			☐	☐	☐
S-37-177-0	☒	☐	5,400 BBL ORGANIC LIQUID STORAGE TANK (#5014) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8) (REPLACEMENT FOR S-37-48-5)			☐	☐	☐

(COMPLETE THE FOLLOWING AS IT APPLIES TO THIS SOURCE)		COMPLIANCE		
		YES	NO	N/A
VARIANCE STATUS	On schedule: In compliance with all conditions:	☐	☐	☐
SOURCE TEST STATUS	Required: YES Performed: YES Excess Emissions: NO	☐	☒	☐
ATC(s) / PTO(s)	Accurate/Current: YES On site: YES Unpermitted Equip: NO Unimplemented: NO	☒	☐	
OPERATING SCHEDULE	Equipment hours comply with ATC/PTO? YES	☒	☐	☐
COMPLAINTS	Are there outstanding complaints against facility? No	☒	☐	
V.E. EVALUATION(s)	Conducted: YES In compliance with visible emission standard: YES	☒	☐	
RECORDS	Maintained: YES Records show compliance: YES	☒	☐	☐
	Meets permit limit for process rates: YES	☒	☐	☐
PORTABLE ANALYZER	Analyzer check shows emissions in compliance with limits:	☒	☐	☐
	Analyzer demonstrated to be in compliance with leak requirements:	☐	☒	☐
CEMS/ OTHER	Proper Maintenance / Calibration Procedures:	☒	☐	☐
MONITORING EQUIP	Have all reports been submitted on time and as required:	☒	☐	☐
BREAKDOWNS	Are there outstanding breakdowns:	☐	☒	☐
HEALTHY AIR LIVING	HAL information discussed with appropriate representative:	☐	☐	☐

ENFORCEMENT ACTION TAKEN: ☐NTC(s) ☒NOV(s) ☐RCAT(s) **Number(s)** Listed under the two-year enforcement history.

INSPECTION FREQUENCY | **Modified as result of emission violation or nuisance:** **Frequency changed to:** **Months.**

COMMENTS:

ATCS not finalized: -7-11; -21-14; -22-14; -25-6; -26-6; -127-6; -177-0.

ATCs finalized but not ready to convert: -4-22; -166-0; -167-0; -176-0 (will be replacing PTO -97)

INSPECTOR SIGNATURE:  **DATE:** 6/17/25 **REVIEWER:** ALEX OREGON **DATE:** 7/23/2025

ADDITIONAL INSPECTION COMMENTS

Reviewed 2024 records.

COGEN

-6-20: Non-compliant DEU. Facility will retain permit active.

-114-8 Solar Tarus 60-7901S Cogen System:

- Unit is fueled by PUC natural gas only. Facility provided vendor's test data (from SoCal) consistent with the natural gas fuel sulfur content. Sulfur daily average was 0.18-grain/100 scf. (*Limit: 1.0 grains of sulfur compounds per 100 dry scf of natural gas.)*
- Daily heat input to the gas turbine engine and duct burner are within limits. Highest noted was 1,214 mscfd on 8/23/24 (limit: 2,032.8 MMBtu/day).
- Weekly records of the exhaust gas concentration of NOx *(limit: 2.5ppmvd)* (as NO2), CO *(limit: 6.0ppmvd @15% O2*), are maintained and compliant. Testing is done weekly.
- Monthly records of the date and time of all NOx, CO, and O2 measurements, the measured NO2 and CO concentrations corrected to 15% O2, and the O2 concentration; and records shall also include a description of any corrective action taken are maintained and in compliance. Unit is tested once a week. Test results within limits.
- Unit was tested at the time of inspection. Test results noted in document 10.
- Records of daily and rolling twelve month natural gas consumption (MMBtu) of gas turbine engine and duct burner are maintained and in compliance. 2023 total SoCal fuel usage was 410,128 MMBtu and Natural Gas HHV 1000 btu/scf.
- Daily and rolling twelve month calculated emissions are maintained and in compliance, as follows: NOx 0.47 tons/yr.; VOC 0.07 tons/yr.; SOx 0.65 tons/yr.; CO 0.37 tons/yr.; PM10 1.32 tons/yr.; NH3 5,156 lbs./Yr. Ammonia Injection Rate: Highest noted at 26.11 on 5/23/24, and catalyst inlet temperature, highest noted at 647.50F on 4/26/24.
- Duration of Startup and Shutdown periods records are maintained and in compliance.
- Unit operated a total of 8,661 hours in 2024.
- Last Source Test was conducted on 10/10/2024 (Testing is required yearly), in compliance.

Emergency Engines

40 CFR 63 subpart JJJJ and ZZZZ are maintained and in compliance.

- -80-4: Total hours operated in 2024 were 1.1 hours (*limit: 20 hrs./yr.*). No emergency hours recorded.
- -81-4: Total hours operated in 2024 were 23 hours (*limit:100 hrs./yr.*). No emergency hours recorded.
- -82-5: Engine was removed replaced with an electric engine in 2018.
- -83-5: Engine did not operate in 2024 were 0.96 hours (*limit: 100 hrs./yr.*) No emergency hours recorded.
- -123-4: Total hours operated in 2024 were 40.2 (*limit: 100 hrs./yr.*). No emergency hours recorded.

Fired Equipment

PTO -1-18:

- Records of total daily and annual duration of startup and shutdown times are maintained and in compliance. Startup and shutdown times were below limits. (*Born Heater limit: 9.7 hrs. and Tulsa Heater 6.2hrs, and shall not exceed 48.3 hrs./yr.*)
- Both units were tested at the time of inspection. Test results noted in document 3.
- 2024 annual average heat input for Born heater was 45.2 MMBtu/hr. and was Tulsa Heater 34.8 MMBtu/hr. (*Limit: 60MMBtu/hr. as measured on an annual average basis, for each heater*).
- Monthly monitoring records of stack concentrations for both heaters (NOx as NO2, CO and O2) are maintained and in compliance. Both units are tested monthly and results were below limits. (*limits for 2024: Tulsa Heater NOx:9ppm CO: 150ppm O2: 3% and Born heater NOx: 15ppm, CO: 150ppm at 3% O2*)
- Born heater Source Test was conducted on 4/9/2024.
- Tulsa heater Source Test was conducted on 12/6/2024.

PTO -2-10: Out of Service all of 2023.

PTO -3-11 KHT:

- Monthly monitoring records of stack concentration of NOx, CO and O2, for each heater; are maintained and in compliance. Units are tested monthly, results below limits (*limits NOx: 25ppm; CO: 50ppm; O2: 3%*)
- Charge Heater and Splitter Reboiler Heater were tested at the time of inspection. Test results noted in document 3.
- Records of startup and shutdown periods are maintained and in compliance. (*Limits: 12 hours and 9 hours respectively*). Facility only records startup and shutdown hours if the unit exceeds the limits, otherwise they are zeroed out.

- Splitter Reboiler and Charger heaters Source Test was conducted on 2/12/25 (36-month intervals)
- Sulfur analysis of fuel combusted is monitored through CEMS.
- Quarterly LDAR records are maintained and in compliance.

PTO -4-20 Platformer:

- Monthly monitoring records of stack concentration of NOx, CO and O2, for each heater; are maintained and in compliance. Units are tested monthly, results below limits (*limits NOx: 25ppm; CO: 50ppm; O2: 3%*)
- Charge heaters #1, 2, and 3 were tested at the time of inspection. Test results noted in document 3.
- Records of startup and shutdown periods are maintained and in compliance. (*Limits: 12 hours and 9 hours respectively*) Platformer heaters #1, #2 and #3 exceeded Startup period for 1 hour each on 12/14/2023. Facility was issued NOV #5032601.
- Quarterly LDAR records are maintained and in compliance.
- Charger Heater #1, #2 and #3 Source Test was conducted on 02/06/25 (on 36-month intervals)

PTO -38 Transmix Unit:

- Daily sulfur content (H2S) of refinery fuel is monitored through CEMS (*limit H2S>162ppm on a 3-hour rolling average basis*)
- H-1 and H-2 stack concentrations of NOx, CO and O2 are tested monthly. Records are maintained and in compliance. (Limits: *Limit: 30 ppmvd NOx @ 3% O2, 400 ppmvd CO @ 3% O2*).
- Unit was tested at the time of inspection. Test results noted in document 3.
- Records of startup and shutdown periods are maintained and in compliance. H-1exceeded startup hours on 6/22/24 for a total a 4.67 hours and H-2 exceed startup on 3/21/24: 2.25 hours; 3/31/24: 2.5 hours and 4/20/24: 3.25 hours. Facility was issued NOV #5035119.
- Quarterly LDAR records are maintained and in compliance.

PTOs -77: Diesel Hydrotreater Unit (DHT); -116: Splitter Reboiler Heater; -118: Naphtha Hydrotreater (NHT); -119: Naphtha Reformer Unit:

- All units are tested monthly. Records of monthly monitoring records of stack concentration of NOx, CO and O2, for each heater; are maintained and in compliance. ***(-77**: limits NOx (as NO2): 25 ppmv @ 3% O2, CO: 50 ppmv @ 3% O2) (-**116**: limits NOx (as NO2): 30 ppmv @3% O2; CO: 239 ppmvd @ 3% O2) (**-118**: limits NOx (as NO2): 25 ppmv @ 3% O2, CO: 150 ppmv @ 3% O2)(-**119**: limits NOx (as NO2): 25 ppmv @ 3% O2, VOC: 0.0055 lb/MMBtu, or CO: 150 ppmv @ 3% O2)*
- All operating units were tested at the time of inspection. Test results noted in document 3.
- -116: Records of daily amount and type(s) of fuel(s) combusted are maintained and in compliance. Highest observed was 280.98 Mscf or 280,890 scf on 12/12/24 (*limit: 338,000 scf/day*).
- Annual records of heat input (MMBtu/hr.) for all units are maintained and in compliance. Total 1751 MMBtu (*No limit*).

PTO -122 SRU #1:

- Daily records of Sulfur production from Claus sulfur recovery plant are maintained and in compliance. Highest day noted was 3 long-tons (*limit: 20 long-tons/day combined with -152*).
- Daily and annual records of SOx emissions from incinerator exhaust are maintained and in compliance. Highest day noted was 33.7 lbs on 9/3/24. 2024 SOx emissions was 2,816.59 lbs./yr. (*limit: 33.8lbs/day and 12,718 lbs./yr.*)
- Unit was tested at the time of inspections. Test results noted in document 3.
- Sulfur analysis of fuel combusted is monitored through CEMS (limit H2S >100ppm)
- Records of Startup and shutdown periods are maintained and in compliance. No exceedances observed (*limit: 37.0 hours and 23.4 hours respectively*).
- Source Test was completed on 5/25/23 and 5/21/24, in compliance (annual testing).

ATC -152 SRU #2:

- Operating schedule alternated with SR#1. Unit last operated on August 2024.
- Daily and annual records of SOx emissions from incinerator exhaust are maintained and in compliance. Highest day noted was 30.9 lbs on 3/28/24. 2024 SOx emissions was 2,056.15 lbs./yr. (*limit: combined with -122: 13,166 lbs./yr.*)
- Records of Startup and shutdown periods are maintained and in compliance. No exceedances observed (*limit: 37.0 hours and 23.4 hours respectively*).
- Sulfur analysis of fuel combusted is not being monitor (RECORDS REQUESTED ON FOLLOW-UP EMAIL)
- Source Test has not been conducted. NOV# 5032888 was issued for failure to source test within 60-days of startup and for failure to certified CEMS unit. Unit has been operating since 6/2021. On 2/21/25, a second NOV #5034823 was issued for failure to source test unit and for failing to certify CEMS.

NG ENGINES

-157; 159; -160; -161; -163; -164; & -165:

- All units are tested monthly. Records of monthly monitoring records of stack concentration of NOx, CO and O2, for each heater; are maintained and in compliance.
- All units operating at the time of inspection were tested. Test results noted in document 4.
- Total hours of operation are maintained and in compliance. 2024 total operating hours: -159: 3,376.7 hours. -160: 5,422.2 hour. -161: 3,939.3 hours. -163: 4,797.2 hours; -164: 5,554.6 hours; -165: 7,281.1 hours.

-7 Flare and CEMS

- H2S is monitored through District's CEMS.
- Daily monitoring records of water level and pressure of water seal that services the flare are maintained and in compliance.
- 2024 annual Method 22 VEE was conducted on 4/3/24 from 2:25pm to 4:25pm by J. Gipson.
- 2024 Annual Flare Monitoring Report received 1/28/2025.
- 2024 annual throughput threshold was 5,578.16 MMBtu (limit: 25,000 MMBtu/yr). 2024 compliant with District Rule 4311 section 5.9.

-127: GDF

- 2024 Gasoline throughput was 173,376 gallons (*limit: 518,344 gals./yr.*). Highest monthly observed was 364bbl in July 2024.
- Weekly maintenance inspections are conducted. Records are maintained and in compliance.
- 2024 static leak test was completed on 3/25/25. NTC 5034232 was issued for failure to conduct static test.

TANKS

-12; -13; -14; -15; -16; -18; -19; -20; -21; -22 -23; -24; -25; -26; -27; -28; -31; -34; -42; -48 -49; -50; -51; -52; -53; -56; -57; -59; -61; -65; -66; -67; -79; -90; -91; -95; -96; -97; -102; -108; -109; -111; -125; -126; -130; -131; -148; -150; -153; -154; -174.

- Quarterly LDAR records are maintained and in compliance.
- -21 and -22: Tanks are under Vapor Recovery System.
- -25: TVP at 0.3 psi at 100F. API gravity at 28.9 tested on 7/17/24.
- -27-5: fixed roof tank and connected to vapor recovery unit.
- -44: Tank is under Vapor Recovery System.
- -61: Tank is under Vapor Recovery System.
- -67, -95 and -96: OOS
- -148:
    - TVP at 6.6 psi; Tested on 8/7/23.
    - Daily throughput at 391 bbl/day based on a monthly average. 2024 total 142,746 bbls. (*limits: 25,000 bbl/day based on a monthly average. 3,125,860 bbl/yr*).
    - Seal Gap test was conducted on 10/2/2023.

TRANSFER RACKS

PTO -8: (Racks A, F, K, L, N)

- Drainage inspections are conducted once a month, compliant.

PTO -43 (Rack G – truck loading operation)

- Drainage inspections are conducted once a month, compliant.
- There were zero disconnects in 2024.

PTO -46 (Rack Q – Liquid loading/unloading operation)

- Drainage inspections are conducted once a month, compliant.
- Daily loadout of liquids are maintained. 2024 total barrels of Diesel was 8,377; Ethanol was 5,815; total barrels of Transmix was 593,893 (*limit: Organic liquids with TVP >1.5 psi 28,000 gals/day*), compliant.
- Monthly results of leak inspections of the loading and vapor collection equipment at each loading arm are maintained and in compliance.

PTO -58 (Rack H – truck loading operation)

- Drainage inspections are conducted once a month, compliant.
- Monthly results of leak inspections of the loading and vapor collection equipment at each loading arm are maintained and in compliance.

PTO -71 (Rack E – truck loading/unloading operation)

- Daily throughput of liquid transferred are maintained.

PTO -93 (Rack C – Truck loading rack and 6 organic liquid loading)

- Type of liquid loaded is PS 1500 which has a TVP less than 1.5 psi.
- 2024 total liquid loaded was 2,912,059 bbls. (*no limit*).

PTO -94 (Rack W) Railcar liquid transfer facility

- Daily records of number of disconnects are maintained and in compliance. Highest observed was a total of 10 disconnects in the month of October 2024. (*limit 144 disconnects/day*)
- Types of liquids/gases transferred are Ethanol, Alkylate, Toluene, Crude, B-100, GEEB, JC747, NG, Butane, Isocotone, Cetane, Transmix and EPA Diesel.

PTO -107 (Rack V) LPG, Natural Gasoline & Mixed light Hydrocarbon loading/unloading

- Daily number of disconnects are maintained and in compliance. Highest observed was a total of 95 disconnects in the month of December 2024. (*limit: 56 disconnects/day*).

PTO -138 (Rack X) Organic liquid transfer facility

- Daily records of volume of organic liquid transferred are maintained and in compliance. Highest noted was 1,130 gpd in January and July 2024 (*limit: 23,016 gal/day*).
- Per SDS, product's TVP is 0.00966 psi (*limit: TVP of liquids transferred shall not exceed 0.05psi at transfer temperature*)
- Type of liquids transferred was Kerosene K-1from tank 3021; JC747 from tanks 3022 and 3023.

PTO -139 Lane 1 South (Rack AA) Crude Oil Unloading Rack

- Daily records of unloading rack throughput are maintained and in compliance. Highest noted was 48,826 gal. in January 2024.
- Results of leak inspections are conducted and in compliance.

PTO -140 Lane 2 Middle (Rack AA) Crude Oil unloading Rack

- Daily records of unloading rack throughputs are maintained and in compliance. Highest noted was 16,688 gallons in the month of May 2024 (*no limit*).
- There were zero disconnects in 2024 (*limit 48 disconnects/day*).
- Results of leak inspections are maintained an in compliance.

PTO -141 Lane 3 North (RACK AA)

- Daily records of unloading rack throughputs are maintained and in compliance. Highest noted was 44,902 in the month of January 2024. (*no limit*).
- Daily records of unloading disconnects are maintained and in compliance. Highest noted was 8.5 disconnects in the month of April 2024 (*limit: 48 disconnects/day*).

PTO -142 Residual Oil Transfer Rack (Rack U)

- Type of liquids transferred: B99/100 to tank 3013 which tied to VRS.

PTO -147 Organic Liquid Unloading Rack (Rack S)

- Daily records of unloading rack throughputs are maintained and in compliance. (*no limit*).
- Daily records of unloading disconnects are maintained and in compliance. Highest noted was 2 disconnects in the month of March 2024 (*limit 20 disconnects/day*).

PTO -155 (Rack R): OOS.

WASTE WATER

-9 Oil/Water Separation Operation

- Annual VOC content test was conducted on 12/23/24. Total VOCs were below 10% by weight (ND).

TWO-YEAR ENFORCEMENT HISTORY						
TYPE	**NUMBER**	**OCCURRED**	**ISSUED**	**STATUS**	**CITATION**	**NATURE OF VIOLATION**
NOV	5031559	07/08/2023	**09/13/2023**	CLOSED	2520, 4702	Failure to monitor and record stack concentration of NOx, CO, and O2 within 5 days of restarting the unit.
NOV	5031563	08/26/2023	09/13/2023	CLOSED	2070, 2201, 2520	Failure to monitor SOx emissions from SRU#1
NOV	5031669	08/26/2023	10/04/2023	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv and late submittal of deviation report.
NOV	5031718	03/22/2023	10/16/2023	CLOSED	2070, 2520, 4623	I. Failure to have tanks equipped with a vapor recovery system.
NOV	5031719	04/20/2023	10/16/2023	CLOSED	2070, 2520, 4623	I. Failure to have tanks equipped with a vapor recovery system.
NOV	5031872	10/02/2023	11/15/2023	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 10/2/2023, 10/3/23, 10/4/23, 10/6/23, 10/10/23 and 10/18/23.
NOV	5032277	05/04/2023	12/26/2023	CLOSED	2070, 2520, 4623	Failed annual gap seal inspection.
NOV	5032279	07/06/2023	12/26/2023	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv.
NOV	5032281	07/17/2023	12/26/2023	CLOSED	2070, 2201, 2520, 4001	Failure to have refinery fuel gas equipped with a CEMS.
NOV	5032285	11/14/2023	12/26/2023	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 11/14/2023
NOV	5032315	12/11/2023	01/02/2024	CLOSED	4307	Exceeding Start up duration as defined in Rule 4703.
NOV	5032354	10/31/2023	01/05/2024	CLOSED	2070, 2201, 2520, 4307	Exceedance of NOx and CO limits
NOV	5032370	12/06/2023	01/08/2024	CLOSED	2070, 2520, 4623	Failure to maintain secondary seal free of tears, holes or openings.
NOV	5032288	11/25/2023	01/24/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 11/21/23 & 11/25/2023
NOV	5032547	11/25/2023	01/30/2024	CLOSED	2070, 2520	I. Failure to comply with H2S limit of 162 ppmv on 11/29/23 II. Failure to comply with H2S limit of 162 ppmv on 11/30/23 III. Failure to comply with H2S limit of 162 ppmv on 11/28/23
NOV	5032548	11/28/2023	01/30/2024	CLOSED	2070, 4623, 4624	I. Discovery of 1 greater than 1,000 PPM leak subject to 4624. II. Discovery of 5 greater than 10,000 PPM leaks subject to 4623.
NOV	5032283	09/18/2023	02/01/2024	CLOSED	2070, 2520	Excess sulfur emissions as detected by Refinery Fuel Gas CEMS and Flare CEMS. Excess sulfur at SRU2 incinerator exhaust. * Amended to reflect all 7 deviation events for the month of September 2023.
NOV	5032568	12/04/2023	02/01/2024	CLOSED	2201, 2520, 4623, 4624	PTO -8: >50,000ppm gas-leak at Manometer (north of VRU compressor) and >10,000ppm gas-leak at Rack A Lane#1 south dry lock; PTOs:-16; -18-; -57; and -102: >50,000ppm gas-leak at PVRVs; PTO -154: 25,000ppm gas-leak at PVRV; PTO -107: LPG Loading Racks: 2,000ppm gas-leak at coupling on hose; 3,000ppm gas-leak at threaded connection (north of load hose on east rack); 200ppm gas-leak at threaded connected of ball valve; 3,000ppm at butane pump seal; and 6,000ppm gas-leak at threaded connection at PRD.
NOV	5032578	12/08/2023	02/02/2024	CLOSED	2070, 2201, 4621, 4623, 4624	Failure to maintain Plant VRU operating and CSA unit in a leak-free condition.
NOV	5032584	12/05/2023	02/02/2024	CLOSED	2070, 2201, 4624, 4625	Failure to maintain waste water pit covered; and Failure to maintain hose cap in a gas-leak free condition.
NOV	5032586	12/04/2023	02/02/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 12/4/23; 12/26/23; 12/27/23; 12/28/23 and 12/29/23.
NOV	5032601	12/14/2023	02/06/2024	CLOSED	2070, 2520, 4306	Exceedance of startup period
NOV	5032742	12/31/2023	03/04/2024	CLOSED	2070, 2201, 2520	Exceeded daily SOx and NOx limit on 12/31/23, 1/2/2024 and 1/3/2024 and failure to conduct daily monitoring testing for SRU2 on 1/1/2024.
NOV	5032754	01/16/2024	03/06/2024	CLOSED	2070, 2520, 4623	Failure to maintain Crude Storage Area Vapor Recovery Unit and Plant Vapor Recovery Unit functional and operating
NOV	5032760	01/24/2024	03/06/2024	CLOSED	2070, 2520, 4455	PTO -1: >50,000ppm gas-leak at fuel gas regulator on Gas Filter Pot; PTO -3: >50,000 ppm gas leak at vent on East KHT compressor; PTO -4: >50,000ppm gas-leak at threaded connection on South compressor; and PTO -77: Open Ended Line (OEL) on suction line.
NOV	5032765	01/28/2024	03/06/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 01/28/2024, 02/12/2024 and 02/13/2024
NOV	5032766	02/13/2024	03/07/2024	CLOSED	2201, 2520, 4306	Excess NOx emissions
NOV	5032774	01/05/2024	03/11/2024	CLOSED	1081, 2070, 2520, 4306	Exceedance of NOx limit during source test.
NOV	5032810	01/08/2024	03/18/2024	CLOSED	2201, 2520, 4623	Failure to maintain Vapor Recovery Units and CEMS functional and operating at all times.
NOV	5032813	01/08/2024	03/18/2024	CLOSED	2070, 2201, 2520	Failure to comply with H2S limit of 100 ppm
NOV	5032888	06/15/2021	04/04/2024	NOV ISSUED	2010, 2201, 2520	i. failure to source test within 60 days of startup ii. failure to certify CEMS unit

NOV	5032935	03/14/2024	04/16/2024	COMPLIANCE ACHIEVED	2070, 2520	Exceedance of the 162ppm H2S limit on 03/14/24, 03/15/24, and 03/16/24.
NOV	5032940	01/08/2024	04/16/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv
NOV	5032947	03/04/2024	04/17/2024	CLOSED	2201, 4307	Excess NOx emissions
NOV	5032763	01/31/2024	04/26/2024	CLOSED	2070, 2201, 2520, 4455	PTO -109: VOC loss detected at pressure vessel's manway; PTO -118: >50,000ppm gas leak; and PTO -121: > 30 dpm at valve
NOV	5033096	05/04/2024	05/22/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv
NOV	5033302	06/17/2024	07/24/2024	COMPLIANCE ACHIEVED	2070, 2520	Failure to comply with H2S limit of 162 ppmv (06/17/24, 06/18/24, 06/19/24)
NOV	5033304	07/06/2024	07/24/2024	CLOSED	2070, 2201, 2520, 4623	Failure to maintain vapor recovery system in operation
NOV	5033343	03/03/2023	08/01/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv; Failure to submit Deviation Report within 10-days of discovery date.
NOV	5033434	12/05/2023	08/20/2024	CLOSED	2070, 2520, 4455	Exceedance of allowable leaks in Table 2 per Rule 4455: Valves; Threaded Connections; and Other components.
NOV	5033305	07/18/2024	08/28/2024	COMPLIANCE ACHIEVED	2070, 2201, 2520, 4301	Failure to comply with H2S limit of 100ppm: -1, -3, -4, -116 on 7-24-24 -77, -118, -119, -122 on 7-18-24, 7-24-24, and 7-26-24 and Failure to comply with H2S limit of 162ppm: -38 on 7-24-24
NOV	5033515	08/07/2024	09/03/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv (08/07/24, 08/08/24)
NOV	5033493	08/06/2024	09/03/2024	CLOSED	2070, 2201, 2520, 4301	Failure to comply with H2S limit of 100ppm
NOV	5033594	12/31/2023	09/17/2024	COMPLIANCE ACHIEVED	2201, 2520	Exceedance of annual average heat input
NOV	5033597	08/12/2022	09/17/2024	COMPLIANCE ACHIEVED	2201, 2520	Exceedance of True Vapor Pressure (TVP) limit of liquids transferred
NOV	5033599	09/02/2022	09/17/2024	COMPLIANCE ACHIEVED	2070, 2201, 2520	Exceedance of H2S limits
NOV	5033677	09/21/2024	10/01/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv
NOV	5033765	08/31/2023	10/16/2024	CLOSED	2070, 2201, 2520	Exceedance of H2S limits
NOV	5033766	11/09/2023	10/16/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv
NOV	5033846	10/21/2024	11/04/2024	COMPLIANCE ACHIEVED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 10/21/24 and 10/25/24
NOV	5033850	10/22/2024	11/04/2024	CLOSED	2070, 2201, 2520, 4623	Failure to maintain secondary seal without holes, tears or openings.
NOV	5033980	11/12/2024	11/21/2024	COMPLIANCE ACHIEVED	2070, 2201, 2520, 4623, 4624	Discoveries found during District annual inspection include: I. Rule 4624: two greater than 1,000ppm gas- leaks. II. Rule 4623 one greater than 10,000ppm gas-leak.
NOV	5033983	11/14/2024	11/21/2024	COMPLIANCE ACHIEVED	2070, 2520, 4455	District Rule 4455 greater than 50,000ppm gas-leak at threaded connection
NOV	5034062	11/25/2024	12/02/2024	COMPLIANCE ACHIEVED	2070, 2201, 2520, 4624	Two greater than 1,000ppm gas-leak discovered during District annual inspection
NOV	5034095	12/03/2024	12/04/2024	COMPLIANCE ACHIEVED	2070, 2520, 4455	One gas-leaks greater than 50,000ppm at DHT compressor, discovered during District's annual inspection.
NOV	5034294	12/17/2024	12/20/2024	COMPLIANCE ACHIEVED	2201, 2520, 4306, 4702	Excess NOx emissions
NOV	5034297	12/17/2024	12/20/2024	COMPLIANCE ACHIEVED	2070, 2520, 4455	Greater than 50,000ppm gas-leak at threaded connection, discovered during District's annual inspection.
NOV	5034298	12/19/2024	12/20/2024	CLOSED	2070, 2201, 2520	Greater than 100ppm gas-leak at valve
NOV	5034357	12/16/2024	12/30/2024	COMPLIANCE ACHIEVED	2201, 2520, 4455, 4623, 4624	Failure to maintain vapor recovery system functional and operating
NOV	5034361	11/26/2024	01/29/2025	COMPLIANCE ACHIEVED	2010, 2070	Failure to maintain a functioning and operating vapor recovery system.
NOV	5034680	01/23/2025	02/04/2025	COMPLIANCE ACHIEVED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 01/23/25
NOV	5034746	02/02/2025	02/11/2025	COMPLIANCE ACHIEVED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 02/02/25
NTC	5034232	06/19/2024	02/25/2025	COMPLIANCE ACHIEVED	2070, 4621, 4622	Failure to conduct and pass the required vapor recovery performance testing.
NTC	5034233	07/10/2024	02/25/2025	CLOSED	4622	Failure to submit an Authority to construct application to either comply with the phase II EVR requirements of VR-501-D by July 9, 2024 or by limiting the annual throughput of gasoline to 480,000 gallons.
NOV	5034823	06/15/2021	02/26/2025	NOV ISSUED	2010, 2201, 2520	Second Notice of Violation: i. failure to source test within 60 days of startup ii. failure to certify CEMS unit
NOV	5034898	03/03/2025	04/02/2025	COMPLIANCE ACHIEVED	2070, 2201, 2520	Failure to comply with: Flare H2S limit of 162ppm on 3/3/25; and

						Fuel gas H2S limit of 84.5ppm on 3/24/25
NOV	5035031	03/25/2025	04/08/2025	COMPLIANCE ACHIEVED	2070, 2520	Failure to maintain CEMS
NOV	5035119	03/21/2024	05/01/2025	COMPLIANCE ACHIEVED	2070, 2520, 4306	Transmix H-1 Heater exceedance of startup period on 6/22/24 and 1/19/25; Transmix H-1 Heater exceedance of shutdown period on 2/23/25, 3/15/25, 3/23/25 and 1/12/25; Transmix H-2 Heater exceedance of startup period on 3/21/24, 3/31/24, 4/20/24, 1/20/25 and 4/12/25; Transmix H-2 Heater exceedance of shutdown period on 12/23/24, 2/23/25, 3/23/25, 4/7/25, and 4/9/25; KHT Charge Heater exceedance of startup period on 01/09/25; NHT Charge Heater exceedance of startup period on 1/20/25; and Platformer Splitter Reboiler Heater exceedance of shutdown period on 1/9/25.

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit BOPD	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-12	5009	Gasoline Tank Farm	4700	Gasoline				Y	Y	Y		11/12/24
-13*	5010	Gasoline Tank Farm	5150	B5 or BlendStock				Y	Y	Y		11/12/24
-14*	5011	Gasoline Tank Farm	5000	Gasoline				Y	Y	Y		11/12/24
-15*	5020	Gasoline Tank Farm	5000	ISO-OCtane				Y	Y	Y		11/12/24
-16	12000	Gasoline Tank Farm	12000	OOS				Y	Y	N	OOS	11/12/24
i-18	10007	Gasoline Tank Farm	10000	Gasoline				Y	Y	Y		11/12/24
-19	10008	Gasoline Tank Farm	10000	Gasoline				Y	Y	Y		11/12/24
-20	10001	Middle Tank Farm	10000	Alkylate				Y	Y	Y		11/14/24
-21	5006	South Tank Farm	5000	Unifinate				Y	Y	Y		12/3/24
-22	5007	South Tank Farm	5000	Unifinate				Y	Y	Y		12/3/24
-23	5008	South Tank Farm	5000	Transmix				Y	Y	Y		12/3/24
-24	3014	South Tank Farm	3000	Unifinate				Y	Y	Y		12/3/24
-25	3026	South Tank Farm	3000	Biodiesel (B-99)	0.3/0.5	7/17/24		Y	Y	N		12/3/24
-26	3027	South Tank Farm	3000	Biodiesel	0.3/0.5	7/17/24		Y	Y	N		12/3/24

Comments
Tanks were surveyed using OGI camera, emissions detected, on accessible components, were quantified using a TVA.

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS

Hydrocarbon Analyzer Make/Number: TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-9	5061	Water Treament Plant	5000	Produce Water								12/19/24
-9	5062	Water Treatment Plant	5000	Produce Water								12/19/24
-9	5063	Water Treatment Plant	5000	Produce Water								12/19/24
-27	37000	Crude Tank Farm	37000	Crude Oil	/11 under VPS	8/2/23		N	Y	N		11/6/24
-28	80000	Crude Tank Farm	80000	Crude Oil				N	Y	N		11/6/24
-31	1000		1000	Water/Oil				Y	Y	Y		
-34	80001	Crude Tank Farm	80000	Crude Oil				Y	Y	N		11/6/24
-42	3300	Gasoline Tank Farm	3600	Lt.Solvent				Y	Y	Y		11/12/24
-44	3019	South Tank Farm	3000	Sour Water				Y	Y	N		12/3/24
-48	5014	Gasoline Tank Farm	5400	OOS				Y	Y	Y	OOS	11/12/24
-49	5015	Gasoline Tank Farm	5400	LN Light Naptha				Y	Y	Y	1350/Valve	11/12/24
-50	1100	Gasoline Tank Farm	1000	Vesta-Diesel Additive				Y	Y	Y		11/12/24
-51	20001	Diesel Tank Farm	20000	Carb Diesel				Y	Y	Y		11/12/24
-52	10000	Middle tank Farm	10000	SB				Y	Y	Y	Empty	11/14/24
-53	10002	Middel Tank Farm	10000	TOL Toluene				Y	Y	Y		11/14/24
-56	505	Gasoline Tank Farm	500	Transmix				Y	Y	Y		11/12/24
-57	5017	Gasoline Tank Farm	5000	LN Light Naptha				Y	Y	Y		11/12/24
-59	20000	Diesel Tank Farm	20000	Carb Diesel				Y	Y	Y		11/12/24

Comments:

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY

Facility #: S-37

Inspector Name: CRISTELA AVALOS

Hydrocarbon Analyzer Make/Number: TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-61	800	Gasoline Tank Farm	800	Biodiesel (B99)				Y	Y	Y		11/12/24
-65	250	Dehy North	250	Oily Water				Y	Y	Y		11/14/24
-66	251	Dehy South	250	Oily water				Y	Y	Y		11/14/24
-67	200	OOS	200	Organic Liquid	/2.7		/2500	Y			OOS	
-79	335	Gasoline Tank Farm	350	Gsoline Additive				Y	Y	Y		11/12/24
-90	2501	Gasoline Tank Farm	2500	Light Platfomatee				Y	Y	Y		11/12/24
-91	2502	Gasoline TankFarm	2500	Light Platfomate				Y	Y	Y		11/12/24
-95	10003	Tracks Tank Farm	10000	Water				Y	Y	N	OOS	
-96	10004	Tracks Tank Farm	10000	AGO	/0.0181		/28,767gal	Y	Y	N	OOS	
-97	3012	Middle Tank Farm	3000	OOS				Y	Y	Y	OOS	11/14/24
-102	10005	Gasoline Tank Farm	10000	PLAT Heavy				Y	Y	Y		11/12/24
-108	S5000	LPG Storage	5000	Natural Gasoline				N	Y	N		12/19/24
-109	S5001	LPG Strorage	5000	Butane				N	Y	N		12/19/24
-111	55000	Tracks Tank Farm	55000	Crude oil				N	Y	N		
-125	3013	Middle Tank Farm	3000	Tallow				N	N	N		11/14/24

Comments: VM&P = Varnish, Mineral Spirits, and Paints

* Tank 200 is located @ end of solvent unit. This tank is used on the process side, possibly as a knockout. This tank historically held product that feed to a truck loadout, the loadout pump has been removed for years.

* Tank 335 – Vertical ladder does not have a cage, due to safety concerns this tank is not checked for leaks by District staff.

* Tank 800 – Tank holds Naphtha and has a vertical ladder. Must be connected to VR when TVP is >0.4psi; when TVP is ≤ 0.4psi VR may be removed. See PTO for throughput restrictions.

* PTOs -108-2 & -109-2 are spheres (pressurized vessels), they are inspected during the LDAR portion of Rule 4455. District Inspection subject to Rule 2201.

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-126	55002	Diesel Tank Farm	55000	Hv. Distillate				Y	Y	Y		11/12/24
-127	55001	Diesel Tank Farm	55000	TC topped Crude								11/12/24
-130	74000 & TVR	Crude Tank Farm	74000	Crude Oil			/ * See Permit	N	Y	N	>10,000ppm at compresor C-600	11/6/24
-131	74001	Crude Tank Farm	74001	Crude Oil			/ * See Permit	N	Y	N		11/6/24
-148	54000	Tracks Tank Farm	54000	Crude Oil								01/6/25
-150	3015	South Tank Farm	3000	Unifinate				Y	Y	Y		12/3/24
-153	16005	Gasoline Tank Farm	17000	ETH Ethanol				Y	Y	Y		11/12/24
-154	16006	Gasoline Tank Farm	17000	PLAT Heavy Platformate				Y	Y	Y		11/12/24
ATC-166	12002		12000									
ATC-167	12003		12000									
-171	3016	South Tank Farm	3000	Renewable Diesel							1918ppm/flange	12/3/24
-172	3017	South Tank Farm	3000	Renewable Diesel (R99)							623ppm flange	12/3/24
-173	3018	South Tank Fam	3000	OOS							OOS	12/3/24
-174	12001	Gasoline Tank Farm	12000	Heavy Naptha								11/12/24
-175	5013	Gasoline Tank Farm	5000					Y	Y	Y		11/12/24
ATC -176	3012		3000									

Comments: VGO = Virgin Gas Oil, lighter than diesel, can be refined to kerosene.K1 = VGO that has not been refined
ATC -176 will be replacing PTO 97.

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
Exempt	5012	Near Flare Compressors	5000	Non-pota	ble water				N			
Exempt	5060	Waste Water Plant	5000	Water					N			
Exempt	6300	Diesel Tank Farm	6000	Water					N			
Exempt	504	Middle Tank Farm	500	OOS					N			
Exempt	5064	SE Water treatement facility	5000	Produced	Water				N			
Exempt	10006	Tracks Tank Farm	10000	AGO					N			
Exempt	16001	South Tank Farm	16000	VGO					N			
Exempt	16002	South tank Farm	16000	Kerosene					N			
Exempt	16003	Diesel Tank Farm	16000	Carb Diesel					N			
Exempt	16004	Diesel Tank Farm	16000	Carb Diesel B20					N			
Exempt	3021	Tracks Tank Farm	3000	K1-Kerosene					N			
Exempt	3022	Tracks Tank Farm	3000	JC747								
Exempt	3023	Tracks Tank Farm	3000	EB-Geeb								
Exempt	5061	Dehy		Produced water								
Exempt	5062	Dehy		Produced water								
Exempt	5063	Dehy		Produced water								

Comments: * Tank 504 – Previously held Kerosene for co-gen, it is currently empty.

COMPONENT LDAR INSPECTION FORM
COGR / 4401 / 4409 / 4623 (Circle Only One)

Owner/Operator: Kern Energy
Site Name/ Lease(s): Crude Storage Area
Inspector(s): C. Avalos, K. Bonn, J. Gonzalez

Registration/PTO/ATC #: S-37
Analyzer(s) #: TVA 6
Inspection Date(s): 11/6/24, 11/12/24, 11/14/24

Equipment (ie. Wells/Tanks/SGs):

CSA Tanks: 80000, 80001, TVR 74001, 37000
20000, 20001, 55000
gasoline TF piping
Tanks VRU

Middle Tank Farm 11/14/24
10000, 10001, 10002
3012, 3013, 3014

Diesel Tank Farm
55002, 2000, 2001
55001

Leak/Open Ended Line Location		Gas/Liq. Leak ppm/rate	Leak Type	Insp. Date	Repair Date	Re-insp. Date
TVR (C-600) Compressor seal (29438)	NOV ☒	23,000 ppm	Major ☒ Minor ☐	11/12/24	11/14/24	11/20/24
offgas piping 5015 - ~~Valve~~ packing (07060)	NOV ☐	1350 ppm	Major ☐ Minor ☒	11/12/24	11/18/24	11/20/24
Tank #10002 - SE Hatch ~~gasket~~ lid flanging	NOV ☐	~~2485~~	Major ☐ Minor ☐	11/14/24	11/21/24	12/3/24
Tank 10002 - Valve (07229) West side of tank	NOV ☐	2,480 ppm	Major ☐ Minor ☐	11/14/24	11/14/24	11/14/24
Tank 10002 - SE Hatch lid flanging	NOV ☐		Major ☐ Minor ☐	12/3/24	12/9/24	12/17/24
	NOV ☐		Major ☐ Minor ☐			
	NOV ☐		Major ☐ Minor ☐			
	NOV ☐		Major ☐ Minor ☐			
	NOV ☐		Major ☐ Minor ☐			
	NOV ☐		Major ☐ Minor ☐			
	NOV ☐		Major ☐ Minor ☐			
	NOV ☐		Major ☐ Minor ☐			

(Mark Critical and/or Essential components with an * next to Location)

Component Count

Total Count: 369

*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

COMPONENT LDAR INSPECTION FORM
COGR / 4401 / 4409 / 4623 (Circle Only One)

Owner/Operator: Kern

Site Name/ Lease(s): South Tank Farm

Inspector(s): C. Avalos & K. Born

Registration/PTO/ATC #:

Analyzer(s) #: TVA #9 & OGI Camera

Inspection Date(s): 12/3/24

Equipment (ie. Wells/Tanks/SGs):
South Tank Farm

Leak/Open Ended Line Location	Gas/Liq. Leak ppm/rate	Leak Type	Insp. Date	Repair Date	Re-insp. Date
3017 Flange - Top of tank (29455) NOV ☐	Gas 623ppm	Major ☐ Minor ☒	12/3/24	12/4/24	12/17/24
3016 Flange - Top of tank (29454) NOV ☐	1918ppm	Major ☐ Minor ☒	12/3/24	12/4/24	12/17/24
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			

(Mark Critical and/or Essential components with an * next to Location)

Component Count: XXXXXXH

Total Count: 35

*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

COMPONENT LDAR INSPECTION FORM
COGR / 4401 / 4409 / 4623 (Circle Only One)

Owner/Operator: Kern Energy

Site Name/ Lease(s): LPG

Inspector(s): C. Avalos, A. Gamino; Born K.

Registration/PTO/ATC #: S-37

Analyzer(s) #: TVA #6

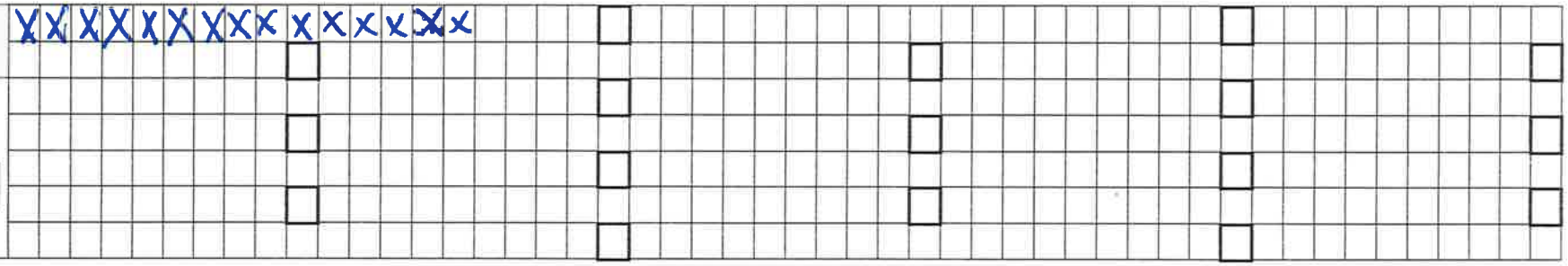
Inspection Date(s): 12/19/24; 01/06/25

Equipment (ie. Wells/Tanks/SGs):
LPG S5000 S5001 WWTP Tracks Farm

Leak/Open Ended Line Location	Gas/Liq. Leak ppm/rate	Leak Type	Insp. Date	Repair Date	Re-insp. Date
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			

(Mark Critical and/or Essential components with an * next to Location)

Component Count



Total Count: 75

*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

RECONCILING LEAKING COMPONENTS
RULE 4623

Owner/Operator: Kern Energy
Facility #: S-37
Location (Lease/Field):
Analyzer(s) #: TVAs # 6, 9 and OGI camera
Inspector(s): C. Avalos, K. Born, J. Gonzalez, A. Garrindo
Date(s): 11/6/24, 11/12/24, 11/14/24,12/3/24, 12/19/24 & 1/6/25

Total Number of Leaks (500 to 10,000 ppmv)	÷	Total Number of Components Inspected (if ≤200 use number, if >200 use percent)	=	Leak Number/Percent	Compliance
4	÷	479	=	0.8%	Y:☒ N:☐ NOV:

Total Number of Major Gas Leaks (>10,000 ppmv)	Compliance	Total Number of Liquid Leaks	Compliance
1	Y:☐ N:☒ NOV: 5033980	0	Y:☒ N:☐ NOV:

Table 10 – Allowable Leaks

Leak Threshold	200 or Less Components Inspected*	More than 200 Components Inspected*
500 – 10,000 ppmv	5	2% of total inspected

* The maximum number of leaks in Table 10 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components inspected during the specified inspection period. Leaks counted toward the allowable leak threshold in Table 10 are still subject to the maintenance and repair requirements of Section 5.9.3 through 5.9.4.

Table 2 – Gas Leak

Non-specific	Minor Gas Leak	Major Gas Leak
Components	500 to 10,000 ppmv	Greater than 10,000 ppmv

Non-specific	Liquid Leak
Components	The dripping of organic liquid at a rate of more than 3 drops per minute

Table 11 – Repair Time Periods

Leak Threshold	Repair Time Period
Minor Leak	14 Calendar Days
Major Leak	2 Calendar Days
Liquid Leak	2 Calendar Days

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37

Location (Lease/Field): Panama Ln & Weedpatch Hwy

Inspector (s): K. Born, J. Gonzales

Date: 11/6/24 ; 11/12/24

Analyzer Number: TVA #6 , TVA #4

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
crude transf pump							Cap	
CSA							Filter pot	1
crude RACK AA							Filter pot	1
Diesel Tank Farm							Pressure Reg	1
Gasoline TF							Filter Pot	1
VRU							Pressure gauge	7
							Filter	3
							Filter Pot	1
							Sight glass	1
							Cap	1
							P.G	1
							Press. Regulator	1
							Sight glass	1
							Filter Pot	1
Total Inspected:	41	182	126	3		9		20
Number of Leaks:				1				

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy
Location: Panama Ln. & Weepatch Hwy
Inspector(s): _____
Analyzer number: _____

ATC / PTO #: S-37
Date: 11/6/24 & 11/12/24

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	PRD	10305			Liq	220						11/15/24	11/20/24

(1) 08 of #20000 pump 10:26:15

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	1,000 to 10,000
Compressors	500 to 10,000	1,000 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy ATC / PTO #: S-37

Location (Lease/Field): Panama Ln & Weedpatch Hwy

Inspector (s): Avalos, C. Born, K. Date: 11/13/24

Analyzer Number: TVA #9

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
Crude Unit					1	4	Filter Rst	1
							Sight glass	4
							Tube fitting	44
							PVRV	1
							Hatch	1
							Connect	1
							Tube fitting	6
							Regulator	3
Total Inspected:	328	234	240		1	6		41
Number of Leaks:			2		3			1

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy
Location: Panama Ln. & Weepatch Hwy
Inspector(s):
Analyzer number:

ATC / PTO #: S-37
Date: 11/13/24

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	TC	29042	Y	N	Gas	11,500ppm	>10K	gas					
2	PVRV	02816 2	Y	N	Gas	2100 ppm		gas					
3	TC	35127	Y	N	Gas	715 ~~385~~ ppm		X					
4	Compressor	C02	Y			15,000 ppm	710K					11/15/24	11/25/24
5	Compressor	C02	Y			10,200 ppm	710K					11/15/24	11/25/24
6	Compressor Vent	C-02	Y			2600 ppm						11/15/24	11/25/24

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000 ~~2000~~	1,000 to 10,000
Compressors	500 to 10,000 ~~2000~~	1,000 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000 ~~500~~	1,000 to 10,000

Tag # 16851

1. under Tulsa heater.
2. sump area PVRV - vent side
3. West end of gas exchanger 6430.63 715ppm @ TC
4. ~~602~~ @ south coverplate on the eastside of C2028.02
5. @ ~~North~~ South coverplate on the ~~east~~ West side
6. Compressor Vent

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37

Location (Lease/Field): Panama Ln & Weedpatch Hwy

Inspector (s): C-Avalos, K. Bloomberg

Date: 11/14/24

Analyzer Number: TVA# 8

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
Middle Tank Farm				1		4	Sight glass	2
							Tube fitting	3
Treater							Regulator	3
Dehy						1	Drain pit	1
							Tube	2
							Sight glass	1
							Hatch	1
Blending area						1		
Platformer					3	1	meter	1
							regulator	2
							PRD	1
							Sight Glass	1
				1				
Total Inspected:	280	330	299	2	3	17		20
Number of Leaks:		1	2					

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern ATC / PTO #: S-37

Location (Lease/Field):

Inspector (s): C. Avalos & K. Blomberg Date: 11/14/24 continue

Analyzer Number: TVA #8

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
Platformer	𝍸 𝍸 𝍸 𝍸 𝍸	𝍸 𝍸 𝍸 𝍸 𝍸	𝍸 𝍸 𝍸 𝍸 𝍸					
	𝍸 𝍸 𝍸 𝍸	𝍸 𝍸 𝍸 𝍸 𝍸	𝍸 𝍸 𝍸 𝍸 𝍸					
		𝍸 𝍸 𝍸 𝍸 𝍸						
		𝍸 𝍸 𝍸 𝍸 𝍸						
		𝍸 𝍸 𝍸						
Total Inspected:								
Number of Leaks:								

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy
Location: Panama Ln. & Weepatch Hwy
Inspector(s): C. Avalos & K. Blomberg
Analyzer number: TVA #8

ATC / PTO #: S-37
Date: 11/14/24

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) NOV	Major Liquid NOV	Open lines NOV	Repair Date	Re-insp. Date
1	Valve	08316-1	Y	N	Gas	875 ppm		X				11/18/24	11/25/24
2	TC	62807864	Y	N		10,200 ppm	710K					11/14/24	11/14/24
3	TC/Plug	21992	Y	N	Gas	81,700 ppm			X			11/14/24	11/14/24

① @ treater - part of North Scrubber
② @ Blending Area TC/plug.
③ @ platformer exchanger 3530.20 - NOV issued #5033783

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	~~500~~ 1,000 to 10,000
Compressors	500 to 10,000	~~500~~ 1,000 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	~~500~~ 1,000 to 10,000

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37

Location (Lease/Field): Panama Ln & Weedpatch Hwy

Inspector (s): C. Avalos & K. Born

Date: 12/3/24

Analyzer Number: TVA #9 ~~Dtl Cancel~~

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
S. Tank Farm	269	297	224	3	2	7	Filter Pot	3
							Tube fitting	42
DHT					2		Regulator	3
							Sight glass	7
							Tube fitting	4
Total Inspected:								
Number of Leaks:								

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy
Location: Panama Ln. & Weepatch Hwy
Inspector(s): C. Avalos & K. Bom
Analyzer number: TVA #9

ATC / PTO #: S-37
Date: 12/3/24

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) NOV	Major Liquid NOV	Open lines NOV	Repair Date	Re-insp. Date
1	~~Compressor~~ Vent	34295	Y		Gas	750,000 ppm			X			12/4/24	12/5/24
~~2~~	~~FC~~		~~Y~~		~~Gas~~	~~2,100~~		X					
2	Vent	34295			Gas	>50,000 ppm			X			12/4/24	12/5/24

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	~~500~~ 1,000 to 10,000
Compressors	500 to 10,000	~~500~~ 1,000 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	~~500~~ 1,000 to 10,000

① @ DHT Compressor 3528.20A -157
~~② @ DHT Compressor~~ So Cal.
② @ DHT Compressor Vent - 157

NIH# 5034095

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37 -3 and -119

Location (Lease/Field): Panama Ln & Weedpatch Hwy

Inspector (s): C-Avalos; K. Trmony

Date: 12/5/2024

Analyzer Number: TVA #9

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
KHT				11	11	11	Regulator	11
							Pressure gauge	11
							Glass	111
							Fitted Tubing	111 111 111 11
NHT				1	1	1111	Fitted Tubing	111
							glass	111
							Reg	1
Total Inspected:	338	446	252	3	2	6		49
Number of Leaks:								

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

COMPONENT INSPECTION FORM
RULE 4455

Company: KERN ATC / PTO #: S-37

Location (Lease/Field):

Inspector (s): C. Avalos & K. Truong Date: 12/5/24 cont'd

Analyzer Number: TVA #9

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
NHT	卌 卌 卌 卌	卌 卌 卌 卌	卌 卌 卌 卌					
	卌 卌 卌 卌	卌 卌 卌 卌	卌 卌 卌 IIII					
	卌 卌 卌 卌	卌 卌 卌 卌						
	卌 卌 III	卌 卌 卌 卌						
		III						
Total Inspected:								
Number of Leaks:								

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37

Location: Panama Ln. & Weepatch Hwy

Inspector(s): _____

Date: _____

Analyzer number: _____

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	~~500~~ 400 to 10,000
Compressors	500 to 10,000	~~500~~ 400 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	~~500~~ 400 to 10,000

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37-119;-7

Location (Lease/Field): Panama Ln & Weedpatch Hwy

Inspector (s): C. Avalos & K. Russell

Date: 12/17/24

Analyzer Number: TVA #9

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
REFORMER					1		Pressure Gauge	
							Stainless Steel Tubing Fitting	
							Sight Valve	
							Hose	1
							KO	
FLARE								
Total Inspected:	147	247	212	4	6	4		28
Number of Leaks:		3	3					

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy
Location: Panama Ln. & Weepatch Hwy
Inspector(s): _____
Analyzer number: _____

ATC / PTO #: S-37
Date: 12/17/24

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	~~Valve~~ *	29633-1			Gas	9,080		Gas					
2	Valve	12749			Liq	244		Liq				12/17/24	12/17/24
3	T.C.	12845			Liq	362		Liq				12/17/24	12/17/24
4	Valve	12851			Liq	1285		Liq				12/18/24	1/6/25
5	Plug/T.C	30199			Liq	50K+		~~Liq~~ Gas	X			12/17/24	12/17/24
6	T.C	18838			Gas	3759		~~Gas~~				12/17/24	12/17/24

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	~~500~~ 1,000 to 10,000
Compressors	500 to 10,000	~~500~~ 1,000 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	~~500~~ 1,000 to 10,000

*1. valve bonnet under component tag 29633, reformer line
2 valve on reformer 26 line, component tag 12749
3. Plug leaking ~~on~~ near pump, threaded connection
4. Valve on "overhead to T-1" line
5. Plug on "overhead to T-1" line, threaded connection
6 Plug on fuel gas line, threaded connection of splitter

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy — ATC / PTO #: S-37-108 & -109 & -9

Location (Lease/Field): LPG

Inspector (s): C Avalos A Garindo — Date: 12/19/24

Analyzer Number: TVA #6

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
LPG	284	203	133	7		5	Fitted tubing	111
							Regulator	111
							Manway	11
WASTE WATER TREATMENT PLANT							Drain	1
							PVRV	1
							P.G	1
							Filter Bod	1
Total Inspected:	284	203	133	7		5		13
Number of Leaks:		1						

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy
Location: LPG
Inspector(s): C. Avalos, A. Gamindo
Analyzer number: TVA #6

ATC / PTO #: S-37
Date: 12/19/24

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	Valve	28179	Y	N	Liq	5,000		Gas				12/20/24	1/6/25

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	~~500~~ 400 to 10,000
Compressors	500 to 10,000	~~500~~ 400 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	~~500~~ 400 to 10,000

Rule @ 35000 - suction line
2201 - Control Valve packing @ 312ppm
Tag #22702 - NOV
① V9 - Control Valve packing

COMPONENT INSPECTION FORM

~~RULE 4409~~ 4455

Company: Kern Energy

Location:

Inspector(s): C Avalos K Born

ATC / PTO #: S-37-38; -122; -121; -120 -169

Date: 01/06/2025

	Flange	Valves	Threaded Connections	Polished Rod Stuffing Box	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
Trasmix					1		III	tubing	
								fittings	1
								Manuely	1
								Filter Pot	1
SRU #1							II	sight glass	1
								regulator	II
								Gauge	III
SWS							1	Cap	1
Amine #1					1111				
Amine #2					1		1	FT	1
Total Inspected:	118	257	155		6		7		35
Number of Leaks:		1							

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: KERN Energy
Location:
Inspector(s): C Avalos & K. Boon
Analyzer number: TVA#8

ATC / PTO #: S-37-38, -122, -121, -120, -169

Date: 1/6/2025

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	Valve	19030	Y		liq		3drop/min					1/6/25	1/6/25

① SWS#2 3drops/min

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valve	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	~~500~~ 1,000 to 10,000
Compressors	500 to 10,000	~~500~~ 1,000 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	~~500~~ 1,000 to 10,000	~~1,000~~ 500 to 10,000

RECONCILING LEAKING COMPONENTS
RULE 4455

Number and percent of leaking components by component type (See Table 2 below):

Component Type	Total Number of leaks (Major + Minor)	÷	Total Number of Component Type Inspected (if <200 use number, if >200 use percent)	=	Leak Rate (%)	Status (OK or NOV)
Valves	6	÷	2196	=	0.3%	OK
Threaded Connections	5	÷	1647	=	0.3%	OK
PRD	1	÷	26	=	1 allowable leak	OK
Compressor	3 leaks at 1compressor	÷	14	=	1 allowable leak	OK
Other components	1	÷	248	=	1 allowable leak	OK
		÷		=		
		÷		=		
		÷		=		
		÷		=		
		÷		=		
		÷		=		
		÷		=		

Table 2: Maximum allowable number or percent of leaking components per inspection period

Component Type	Maximum Number of Leaks for 200 or less Components Inspected	Maximum Percent or Number of Leaks for more than 200 Components Inspected
1. Valves	1	0.5% of number inspected
2. Threaded Connections	1	0.5% of number inspected
3. Flanges	1	0.5% of number inspected
4. Pumps	2	1.0% of number inspected
5. Compressors	1	1 leak
6. Pressure Relief Devices (PRD)	1	1 leak
7. Other component types not listed in items 1-6 above	1	1 leak
8. Pipes	2	2

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	11/12/24	11/12/24	11/12/24	11/12/24	11/12/24	11/12/24
PTO Number:	-8-38	Exempt	-93-5	Exempt	-71-7	-43-2
Pump HP:					25	15
Product Type:	Gasoline; Diesel blending		PS1500		Transmix	Solvent
TVP:						
Leaks:	See Comments	NA	None	NA	None	None
Number of Disconnects/Day:	NA		NA		NA	Zero
Daily Throughput:	NA		NA			NA
Daily Records Maintained:	SAT		SAT		NA	SAT
Leak Inspection Conducted:	NA		SAT		NA	SAT
Loading Rack ID:	A.F.K.L.N	B	C	D	E	G
Inspector:	CA	CA	CA	CA	CA	CA

Comments:
Rack A, Lane 3 hose vapor connection: 18,000ppm – NOV #5033980 was issued for leaks.

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.
** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.
*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	11/12/24	11/12/24	11/12/24	11/12/24	11/25/24	11/25/24
PTO Number:	-58-4	Exempt	Exempt	Exempt	Exempt	Exempt
Pump HP:	29					
Product Type:					Gasoline Additives	Pooling Station
TVP:						
Leaks:	None	None	None	NA	None	None
Number of Disconnects/Day:	NA					
Daily Throughput:	NA					
Daily Records Maintained:	SAT					
Leak Inspection Conducted:	SAT					
Loading Rack ID:	H	I	J	M	O	P
Inspector:	CA	CA	CA	CA	CA	CA

Comments:

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.

** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.

*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	11/25/24	11/25/24	11/25/24	11/25/24	11/25/24	12/4/23
PTO Number:	-46-7	-155	-147-2	-142-4	-107-5	-94-8
Pump HP:	30	30	30	<50		
Product Type:	Diesel, Ethanol; transmix; tolune	OOS	B100	Tallow	LPG, NG, Butane	Butane, JC747 blend component, B100, Ethanol, Alkylate
TVP:						
Leaks:	None		None	None	See Comments	See comments
Number of Disconnects/Day:	NA		2/mo	NA	/Mo.	10/Mo
Daily Throughput:	w/i limits	OOS		NA	NA	NA
Daily Records Maintained:	SAT		SAT	YES	SAT	SAT
Leak Inspection Conducted:	SAT		NA	NA	NA	NA
Loading Rack ID:	Q	R	S	U	V	W
Inspector:	CA	CA	CA	CA	CA	CA

Comments:
Rack V – LPG Loading Racks: NOV #5034062 was issued for leaks.
2,600ppm @ valve;
Rack W – LPG Loading Racks: NOV #5034062 was issued for leaks.
1,600ppm@ TC spot 3.

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.
** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.
*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	11/25/24	11/25/24	11/6/24	11/12/24	11/25/24	11/25/24
PTO Number:	-138-4	-143-4	-139-4, 140-4,141-2	Exempt	Exempt	-67
Pump HP:	15	<50				
Product Type:	JC747, Kerosene, AGO	AGO	Crude Transmix			OOS
TVP:						
Leaks:	None	None	See Comments	NA	NA	
Number of Disconnects/Day:	NA	NA	8/mo & 2/mo			
Daily Throughput:		NA				
Daily Records Maintained:	SAT	SAT				OOS
Leak Inspection Conducted:	NA	NA				
Loading Rack ID:	X	Y	AA	BB	CC	T
Inspector:	CA	CA	CA	CA	CA	CA

Comments:

Rack AA - Lane 1:
661ppm @ hose collar connection, unloading west hose.
538ppm @ hose cap, unloading west hose.
2,800ppm @ valve bonnet – issued NOV 5033980

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.
** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.
*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

LEAKING COMPONENTS
RULE 4624

Owner/Operator: Kern Energy

Registration/PTO/ATC #: S-37-8; -71; -93; -58; -43; -46; -139; -142; -147; -107; -94; -143; -138

Site Name/ Lease(s): Racks A, E, C, F, H, G, K, L, M, N, Q, S, V, W, Y, X, AA

Analyzer(s) #: TVA 4, 6, 9

Inspector(s): C. Avalos, J. Gonzalez and E. Woods

Inspection Date(s): 11/12/24 and 11/25/24

Equipment Type	Leak Location	Repair Tag #	Concentration (ppm or %)	Minor (500ppm to <1,000ppm)	Major (1,000 +) **NOV**	Inspection Date	Repair Date	Re-Insp. Date
Racks A, E, C, F, H, G, K, L, M, N, Q, S, V, W, Y, X, AA	Rack A Lane 3 Hose connector		18,000		X	11/12/24	11/13/24	11/20/24
	Rack AA: Valve		2,800		X	11/12/24	11/15/24	11/20/24
	Rack AA: Lane 1 Cap of West hose		538	X		11/12/24	11/13/24	11/20/24
	Rack AA: unloading west hose at collar		661	X		11/12/24	11/13/24	11/20/24
	Rack V: Valve	33744	2,600		X	11/25/24	11/26/24	12/03/24
	Rack W: TC @spot 3	22529	1,600		X	11/25/24	11/26/24	12/03/24
Total Number of Leaks:				2	4			

Component	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Count	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Total Count:	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
842	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	I	I																														

*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

Table 3 – Repair Time Periods	
Type of Leak	Repair Time Period
Liquid Leak	72 hours
Gas Leak	72 hours

Table 4 – Number of Allowable Leaks	
Minor Leaks	2% of Number Inspected
Major Leaks	0

Total Count	2% Allowable	NOV or OK
842	17	OK

Stationary Gas Turbine Inspection Report
Rule 4703

Use this form in conjunction with the Compliance Inspection Summary

Inspection Type: ☒ Compliance ☐ Start-Up ☐ Re-Inspect ☐ Complaint ☐ Other

Company: Kern Energy ATC / PTO #: S-37-114

Contact: Gabe Castro Title: Environmental Mangr. Phone: _____

Location: Panama Lane and Weedpatch Hwy

Sec / Utm Sec: _____ Township / Utm West: _____ Range / Utm North: _____

All items are to be checked at the time of each Inspection.

EQUIPMENT:

Turbine Mfg: Solar-Tarus Model: 60-7901S S/N: _____

Maximum Heat Input: 5.5 ☒ Mw ☐ Btu/Hr Shaft H.P.? ☐Y / ☐N

Operating Cycle: ☐ Simple Cycle ☐ Combined Cycle Fuel Type: ☒ Gas ☐ Liquid

Control Equipment: ☒ SCR ☐ Nh3 Injection ☐ DLN Combustors ☐ Other _____

Emissions Category: ☐ Tier 1 ☐ Tier 2 ☐ Tier 3 ☐ Tier 4

Exempt From 4703? ☐ Laboratory Unit ☐ Firefight / Flood Control ☐ Emergency ☐ < 4mw & 877hr

Monitoring: ☐ CEMS ☒ Alternate Monitoring ☐ Op Characteristics

Gen Set Mfg: _____ Model: _____ S/N: _____

Max Output: _____ ☐ KW ☐ Kva ☐ 120 Vac ☐ 220 Vac ☐ 440 Vac

INSPECTION DATE:	11/13/24				
Conditions:					
OAT (°F):	64F				
Wind Speed (mph):	3mph				
Wind Direction:	WNW				
Time In:	1:08 pm				
Time Out:					
Hour Meter Reading:					
Actual Hours Operated:	8,661				
Lube Oil Vent VEE:	☒Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐ Sat / ☐Ns	☐ Sat / ☐Ns
Turbine Inlet Temp:	566F				
SCR Inlet Temp:	576F				
NH_3 Inject Rate:	14.1lb/hr				
Stack Temp:	299F				

Inspection Date:	11/13/24				
Variance:					
On Schedule?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Compliance w/conditions?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Process Rates:					
Raw – Comply?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Finish – Comply?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Fuel – Comply?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Waste:					
Handling?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Storage?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Disposal?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Source Test:					
Date Last Test?	10/10/24				
Excess Emissions?	☐Y / ☒N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
CEMS:					
Proper Cal. Procedure?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Reports?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
ATC /PTO:					
On Site?	☒Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Accurate/Current?	☒Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Unpermitted Equipment?	☐Y / ☒N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Visible Emissions?	☒Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Records?	☒Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Nuisance?	☐Y / ☒N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Violation Observed?	☐Y / ☒N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Issued:					
NOV#					
NTC#					
Inspector:	CA				
Supervisor / Lead:					
Review Date:					

SOURCE: MULTI-ENGINE FORM (revised 10/27/09)

PTO/ATC#: S-37	-80	-81	-82	-83	-123					
Engine Mfg:	Detroit	Cummins	Waukesha	Waukesha	Caterpillar					
Model:	12V71T	NT855F1	35GZU-15866	WAKB-10F	3408D1TA					
Horsepower / Tier	471	225	60	150	481	/	/	/	/	/
Family Name:										
S/N:	12VA075097			230263						
Applicable District Rule:	4702	4702	4702	4702	4702					
Engine Use:	Emergency	Emergency	Emergency	Emergency	Emergency					
Allowable hours:	20	100	100	100	100					
Engine powers:	Generator	Firewater	Firewater	Compressor	Firewater					
Fuel:	Diesel	Diesel	NG	NG	Diesel					
[1]Induction:	Turbo	Turbo	Naturally Asp	NaturallyAsp	Turbo					
[2]Exhaust:	Uncontrolled	Uncontrolled	Uncontrolled	Uncontrolled	Uncontrolled					
[3]Exhaust stack:	Flapper	Flapper	Flapper	Flapper	Flapper					
[4]Crankcase vent:	PCV	PCV								
Timing Certificate on File:										
[5] Rich Burn/Lean Burn				Rich						
Drinking Water System Engine?										
Is it De-Rated:										
[6]How is it de-rated:										
Inspection Date:	11/13/2024	1/6/2025	11/13/2024	11/13/2024	11/12/2024					
[7]VEE: SO/VEE(pass or fail) or No	SB	OP	ABND	SB	SB					
Hour Meter Reading:	2178	906.1		116.7	288.6					
Last yrs Meter Reading:	2176	883.7		115.8	260.8					
[8]Hours Operated per Year	2	22.4		0.9	27.8					
Fuel Meter Reading:										
Catalyst Temp Inlet/Outlet:	/		/	/	/	/	/	/	/	/
Analyzer Results (CO):/limits										
Analyzer Results (NOx):/limits										
Analyzer Results (02):/limits										
Source Test Date:										
Req. Maint. Performed:										
Monthly Monitoring Records:	SAT	SAT	SAT	SAT	SAT					
Inspection Results:	SAT	SAT	SAT	SAT	SAT					.

Inspector Initials:	CA	CA	CA	CA	CA					

MULTIPLE FIRED EQUIPMENT FORM

Company Name:		Kern Energy				Facility:			S-37			
Contact & Phone:		Gabe Castro				Inspector Name:			C. Avalos, K. Blomberg, K. Truong, K. Russell, K. Born			
Inspection Date:		11/13/24; 11/14/24; 12/3/24; 12/5/24; 12/17/24; 1/6/25				Portable Analyzer Make/ Number:			Testos 6, 7, 9			
PTO	**Equip #**	**Refining Unit**	**Rating (MM/BTU)**	**Burner Mfg.**	**Burner Model**	**Serial #**	**Fuel Type**	**Analyzer Results NOx-CO-O2**	**Permit Limits Nox/CO ppm**	**Stack °F**	**VEE/ SO**	**Other**
-1	Tulsa	Crude	60				RFG/NG	8.4-0-7.64	9/150			Testo #9 (11/13/24)
	Born	Crude	60				RFG/NG	13.7-0-4.12	15/150			Testo #9 (11/13/24)
-3	Charge	Unifiner	11.4	Zeeco	GLSF-10		RFG/NG	22.3-0-10%	25/50		SO	Testo #9 (12/5/24)
	Splitter Reboiler	"	12.5	Zeeco	GLSF-10		RFG/NG	16.4-1-7%	25/50		SO	Testo #9 (12/5/24)
-4	Charge#1	Platformer	29.3	Zeeco	GLSF-12		RFG/NG	15.7-0-6.9%	25/51		SO	Testo #9 (11/14/24)
	Charge#2	"	17.9	Zeeco	GLSF-12		RFG/NG	16.9-0-6.7%	25/52		SO	Testo #9 (11/14/24)
	Charge#3	"	11.9	Zeeco	GLSF-10		RFG/NG	18.5-0-8.5%	25/53		SO	Testo #9 (11/14/24)
-6	Coen	"										DEU
-38	Tube Heater (H-1)	Trasmix	3.75				RFG/NG	24-0-2.15%	30/400		SO	Testo #7 (1/6/25)
	Tube Heater (H-2)	"	3.67				RFG/NG	SB	9/250		SB	SB
-77	Charge	DHT	18	Zeeco	GLSF-11		RFG?	20.1-0-4.7%	25/50		SO	Testo 9 (12/3/24)
	Reboiler	DHT	18	Callidus	LE-CSG		RFG?	21.6-0-2.3%	25/150		SO	Testo 9 (12/3/24)
-116	Splitter Reboiler	Platformer Splitter	14.1				RFG/NG	23.8-2-3.5%	30/239			Testo 9 (11/14/24)
-118	Charger	NHT	12.6	John Zink			RFG/NG	24.5-44-7%	25/150		SO	Testo 7 (12/17/24
	Reboiler	NHT	11.1				RFG/NG	30-0-5.3%	25/150		SO	Testo 7. Avrg NOX 29.9ppm / NOV
-119	Charger#1	Reformer	25.7	John Zink			RFG/NG	22.2-0-5.5%	25/150		SO	Testo 7 (12/17/24)
	Charger#2	"	13.4	John Zink				17.9-0-5%	25/150		SO	Testo 7 (12/17/24)
	Charger#3	"	8.9	John Zink				17.9-0-5%	25/10		SO	#2 &#3 use the same port
	Splitter/Stabilizer	"	8.3	John Zink			RFG/NG	SB	9/150		SB	Heater was being serviced
-122	Incinerator	SRU #1	2.5	John Zink			RFG/NG	28.9-0-7.26%	95/150		SO	Testo #7 (1/6/25)
ATC-152	Incinerator	SRU#2	1.9	Zeeco	GB-8S		RFG/NG		95/150			Not ready for startup. ST needs to be completed
-158	Boiler #12	Crude Unit	27.6	Cleaver Broo	700-800-250ST		NG	2.7-0-5.44%	5/25		SO	Testo 9 (11/13/24)
Comments:												

SOURCE: MULTI-ENGINE FORM (revised 10/27/09)

PTO/ATC#:	157	159	160	161	163	164	165			
Engine Mfg:	Wauksha	Wauksha	Wauksha	Wauksha	Wauksha	Wauksha	Wauksha			
Model:	F18G	F18SE	F18SE	F18SE	F18SE	F18SE	F18SE			
Horsepower / Tier	240	310	310	310	310	310	310	/	/	/
Location	DHT Recyc	North Platf	South Platf	KHT West	KHT East	NHT Recy	Reforner Recycler			
S/N:	5283705292	5283705407	5283705396	5263705417	5283705763	5283705788	5283705788			
Applicable District Rule:	4702	4702	4702	4702	4702	4702	4702			
Engine Use:	Fulltime	Fulltime	Fulltime	Fulltime	Fulltime	Fulltime	Fulltime			
Allowable hours:	NA	NA	NA	NA	NA	NA	NA			
Engine powers:	Compressor	Compressor	Compressor	Compressor	Compressor	Compressor	Compressor			
Fuel:	NG	NG	NG	NG	NG	NG	NG			
[1]Induction:	Natural Spire	Natural Spire	Natural Spire	Natural Spire	Natural Spire	Natural Spire	Natural Spire			
[2]Exhaust:	Catalytic	Catalytic	Catalytic	Catalytic	Catalytic	Catalytic	Catalytic			
[3]Exhaust stack:	Open	Open	Flapper	Flapper	Open	Flapper	Flapper			
[4]Crankcase vent:										
Timing Certificate on File:										
[5] Rich Burn/Lean Burn	Rich	Rich	Rich	Rich	Rich	Rich	Rich			
Drinking Water System Engine?	No	No	No	No	No	No	No			
Is it De-Rated:	No	No	No	No	No	No	No			
[6]How is it de-rated:										
Inspection Date:	12/17/2024	11/14/2024	11/14/2024	12/5/2024	12/5/2024	12/17/2024	12/17/2024			
[7]VEE: SO/VEE(pass or fail) or No	SO	SB	SO	SO	SB	SO	SO			
Hour Meter Reading:	NA	NA	NA	NA	NA	NA	NA			
Last yrs Meter Reading:	NA	NA	NA	NA	NA	NA	NA			
[8]Hours Operated per Year										
Fuel Meter Reading:										
Catalyst Temp Inlet/Outlet:	/	/	/	/	/	/	/	/	/	
Analyzer Results (CO):/limits	36 /56	/56	10 / 56	3 / 56	/56	12 / 56	0 / 56			
Analyzer Results (NOx):/limits	3.1 /5	/5	3.7 / 5	0.6 / 5	/5	3.5 / 5	15.01 / 5			
Analyzer Results (02):/limits	1.53 / 15%		0 /15%	1.29 / 15%		0.3 /15%	/15%			
Source Test Date:	1/18/2024	5/2/2024	12/21/2022	8/28/2024	2/26/2024	9/12/2023	9/12/2023			
Req. Maint. Performed:	SAT	SAT	SAT	SAT	SAT	SAT	SAT			
Monthly Monitoring Records:	SAT	SAT	SAT	SAT	SAT	SAT	SAT			
Inspection Results:	SAT	SAT	SAT	SAT	SAT	SAT	NOV		.	

Inspector Initials:	CA	CA	CA	CA	CA	CA/	CA			

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

☐ Northern Region Office
4800 Enterprise Way
Modesto, CA 95356-8718
(209) 557-6400

☐ Central Region Office
1990 E. Gettysburg Ave.
Fresno, CA 93726-0244
(559) 230-5950

☒ Southern Region Office
34946 Flyover Court
Bakersfield, CA 93308-9725
(661) 392-5500

Gasoline Vapor Recovery Inspection Form

Station Name: Kern Oil & Refining Co. PTO: S-37-127-4

Location: Panama Lane & Weedpatch Hwy City: Bakersfield Phone # : (661) 845-0761 office

Compliance Contact: Thomas Landeros Title: Environnmental Advisor

Inspection Type: ☒Compliance ☐ Complaint ☐ Start Up Start Up Date: _____ Test Date: _____

Follow-up to: _____ Notice of Violation # _____ Notice to Comply # _____

Phase I					
Executive Order: **VR-401-C**					
☐UST	☒AST	Tank Type: **Fireguard**			
		Standing Loss Control Compliant? **Yes**			
		Configuration: **Two-point**			
Tank Measurements					
Tank Size		9,000	3,000		
Product Type		87	Diesel		
Location		E	W		
Fill Config.		remote			
Tank Depth					
Fill Tube Length					
Diff (6" or less					

Phase II		
Executive Order: **G-70-52AM**	Type: **Balance**	Nozzles: 1
Phase II Control Type: **None**	PMC Version: N/A	
ISD		
ISD Installed? **No**	ISD Type:	ISD Version:
*if ISD is not installed facility is limited to 600,000 gallons/year		
ISD Currently in alarm?	Alarm History log on-site?	
Is facility responding to alarms?		
Maintenance		
Maintenance Required? **N/A**	Maintenance Performed?	
Date of last maintenance inspection:		
Self-Inspections		
Self-Inspection Records: **Yes**	Self-inspection frequency: **Monthly**	
Throughput: **173,376 gals.**		

Inspection result: ☐ **No defects noted** ☒ **Defects noted (below):** Items corrected during inspection

Location	Product	Equipment	Defect	Result/Action required

Comments:

Inspector: Cristela Avalos Date: 01/06/25

When repairs are complete call: _____ Signature of Receipt: _____

NOTE: CA Health & Safety Code, Section 41960.2 (a) – Maintenance of Installed Systems. (e) Requires that the above listed 7-day deficiencies be repaired within 7 days. Failure to do so will result in legal action.

For important updates and information regarding gasoline dispensing operation requirements, please join our email notification list for Gasoline Vapor Recovery at: http://www.valleyair.org/lists/list.htm

HEALTHY AIR LIVING
www.healthyairliving.com
Make one change for clean air!

FLARE INSPECTION FORM

Company: **Kern Energy** **Permit #:** **S-37-7**

Contact: Gabe Castro Phone #: 661-845-0761

Location: 7724 E. Panama Lane Sec: _____ T: _____ R: _____

Equipment #: _____ Type of Unit: Flare

Make of Unit: JOHN ZINK STF-S-8 STEAM ASSIST FLARE Model: _____ Serial #: _____

BTU/HR Rating: Unknown Opacity Limit: Method 22; any 5 minutes during 2 consecutive hours

Fuel Type: ☐ H2S Gas ☐ Natural Gas ☒ Produced Gas ☐ N/A

Permitted Operating Schedule: 25,000 MMBtu/yr.

Inspection Date:	12/17/24				
VEE Conducted:	☒Sat ☐Ns ☐N/A	☐Sat ☐Ns ☐N/A	☐Sat ☐Ns ☐N/A	☐Sat ☐Ns ☐N/A	☐Sat ☐Ns ☐N/A
Determined by:	☐VEE/ ☒SO	☐VEE/ ☐SO	☐VEE/ ☐SO	☐VEE/ ☐SO	☐VEE/ ☐SO
Hrs Operated:	NA				
MMscf/year:	5,578 MMBtu				
MMscf/day:	NA				
H_2S ppm:	162 ppm (limit)				
Permits Posted:	☒Yes ☐No	☐Yes ☐No	☐Yes ☐No	☐Yes ☐No	☐Yes ☐No
Inspector:	CA				

Comments:

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT
COMPLIANCE INSPECTION SUMMARY

INSPECTION TYPE: ☒ COMPLIANCE ☒ START-UP ☐ VARIANCE ☐ BREAKDOWN ☐ OTHER:

SOURCE NAME: KERN ENERGY EPA DESIGNATION: TITLE V

LOCATION: PANAMA LN & WEEDPATCH HWY CITY: BAKERSFIELD FID#: S-37

CONTACT & TITLE: GABE CASTRO PHONE: 661-845-0761 EMAIL: GCASTRO@KERNENERGY.COM

INSPECTION DATE: 1/6/26; 1/7/26; 1/15/26; 5/5/26; 5/6/26; 5/13/26; 5/14/26; 5/20/26; 5/26/26;5/28/26; 6/3/26 INSPECTOR(s): CRISTELA AVALOS

ACCOMPANIED BY: R. CHAVEZ; S. MILLER; K. BORN; K. BLOMBERG; C. CARRILLO JOINT INSPECTION REQUIRED WITH:

HEALTHY AIR LIVING CONTACT: TITLE: PHONE:

INSPECTED EQUIPMENT				OPERATING		COMPLIANCE		
PERMIT UNIT	ATC	C/O	EQUIPMENT DESCRIPTION *SELECT ALL:*	YES OP SB	NO DEU OOS ABND	YES Y	NO N	ALT. FREQ ALT
S-37-0-4	☐	☐	Facility-Wide Requirements			☐	☐	☐
S-37-1-15	☒	☐	MODIFICATION OF 120 MMBTU/HR CRUDE UNIT INCLUDING ONE DESALTER, 4 FRACTIONATION VESSELS, STRIPPER, 2 ACCUMULATORS, LIGHT NAPHTHA STABILIZER, KNOCKOUT DRUM SCRUBBER, 60 MMBTU/HR TULSA HEATERS INC. PROCESS HEATER, 60 MMBTU/HR BORN HEATER AND 35 HEAT EXCHANGERS: REPLACE ONE OF THE FRACTIONATION VESSELS			☐	☐	☐
S-37-1-18	☐	☐	120 MMBTU/HR CRUDE UNIT INCLUDING ONE DESALTER, 4 FRACTIONATION VESSELS, STRIPPER, 2 ACCUMULATORS, LIGHT NAPHTHA STABILIZER, KNOCKOUT DRUM SCRUBBER, 60 MMBTU/HR TULSA HEATERS INC. PROCESS HEATER WITH CLEARSIGN MODEL CORE LOW NOX BURNERS, 60 MMBTU/HR BORN HEATER WITH CLEARSIGN MODEL CORE LOW NOX BURNERS, AND 35 HEAT EXCHANGERS	OP		☐	☒	☐
S-37-2-10	☐	☐	RERUN UNIT INCLUDING PRE-FLASH DRUM, FRACTIONATOR, STRIPPER, ACCUMULATOR, AND ASSOCIATED VALVES, FLANGES, AND CONNECTORS		DEU	☒	☐	☐
S-37-3-11	☐	☐	KEROSENE HYDROTREATER UNIT (KHT) INCLUDING A SPLITTER, A REACTOR, A SEPARATOR, 3 ACCUMULATORS, 11.4 MMBTU/HR CHARGE HEATER WITH ZEECO GLSF-10 LOW NOX BURNERS AND 12.5 MMBTU/HR SPLITTER REBOILER HEATER WITH ZEECO GLSF-10 LOW NOX BURNERS AND COMPRESSOR POWERED BY IC ENGINE S-37-163	OP		☒	☐	☐
S-37-4-20	☐	☐	PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSORS	OP		☒	☐	☐
S-37-4-22	☒	☐	MODIFICATION OF PLATFORMER UNIT INCLUDING SEPARATOR, ADSORBER, 3 REACTORS, 4 FT. DIA. STABILIZER TOWER, ACCUMULATORS, 29.3 MMBTU/HR CHARGE HEATER #1 WITH ZEECO GLSF-12 LOW NOX BURNERS, 17.9 MMBTU/HR CHARGE HEATER #2 WITH ZEECO GLSF-12 LOW NOX BURNERS, AND 11.9 MMBTU/HR CHARGE HEATER #3 WITH ZEECO GLSF-10 LOW NOX BURNERS AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSOR:INSTALL CHLORIDE SCRUBBER AND REVISE EMISSION FACTORS USING CORRELATION EQUATION			☐	☐	☐
S-37-5-4	☐	☐	LIQUID-LIQUID MEROX SWEETENING UNIT INCLUDING MIXER, CAUSTIC SETTLER, CATALYST INJECTION PORT, AND ASSOCIATED PUMPS AND PIPING	OP		☒	☐	☐
S-37-6-20	☐	☐	49.0 MMBTU/HR COEN, MODEL #D-57, DUAL-FIRED INDUCED DRAFT WATER TUBE BOILER #6 - REPLACEMENT STANDBY BOILER FOR THE TURBINE AND/OR DUCT BURNER (COGENERATION UNIT S-37-114)		DEU	☒	☐	☐
S-37-7-8	☐	☐	JOHN ZINK STF-S-8 STEAM ASSIST FLARE WITH CONSTANT IGNITION PILOTS, INCLUDING THE FOLLOWING GAS RECOVERY EQUIPMENT: THREE ELECTRIC DRIVEN GAS COMPRESSORS C-04, C-02 AND C-03 (250 HP EACH), EIGHT KNOCKOUT POTS, ONE SEAL POT, TWO HEAT EXCHANGERS, TWO STEAM DRIVEN LIQUID RECOVERY PUMPS, AND THREE ELECTRIC DRIVEN LIQUID RECOVERY PUMPS (2 HP)	OP		☒	☐	☐
S-37-8-37	☒	☐	MODIFICATION OF ORGANIC LIQUID LOADING AREAS AND REFINERY VAPOR RECOVERY SYSTEM SERVING TANK S-37-150, AND '-171 THRU '-173 AND INCLUDING COMPRESSOR(S), LOADING RACKS (RACKS A, F, K, L, N) WITH 10 PRODUCT LINES AND 9 VAPOR RETURN LINES: CONNECT VAPOR CONTROL SYSTEM TO S-37-175	OP		☐	☒	☐
S-37-9-13	☐	☐	OIL/WATER SEPARATION OPERATION INCLUDING CORRUGATED PLATE SEPARATOR (DORMANT), INDUCED AIR FLOATATION UNIT, DRAIN PIT, FOUR FILTERS, AND THREE 5,000 BBL STORAGE TANKS (#5061, 5062, AND 5063)	OP		☐	☒	☐

S-37-12-4	☐	☐	210,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #5009 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-13-4	☐	☐	210,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #5010 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-14-4	☐	☐	210,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #5011 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-15-5	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5020 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-16-7	☐	☐	504,000 GALLON FIXED ROOF TANK CONNECTED TO VAPOR CONTROL SYSTEM S-37-8	OP		☒	☐	☐
S-37-18-4	☐	☐	420,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #10007 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-19-4	☐	☐	420,000 GALLON FIXED ROOF GASOLINE STORAGE TANK #10008 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-20-5	☐	☐	420,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #10001 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8	OP		☒	☐	☐
S-37-21-14	☒	☒	MODIFICATION OF 210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5006: UPDATE LEAK DETECTION AND REPAIR CONDITIONS FOR RULE 4623 COMPLIANCE	OP		☒	☐	☐
S-37-22-14	☒	☒	MODIFICATION OF 210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5007: UPDATE LEAK DETECTION AND REPAIR CONDITIONS FOR RULE 4623 COMPLIANCE	OP		☒	☐	☐
S-37-23-9	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5008 SERVED BY REFINERY SHARED VAPOR RECOVERY SYSTEM LISTED ON S-37-8	OP		☒	☐	☐
S-37-24-6	☐	☐	126,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #3014 SERVED BY VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-25-6	☒	☒	MODIFICATION OF 126,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #3026: ADD LEAK DETECTION AND REPAIR CONDITIONS FOR RULE 4623 COMPLIANCE	OP		☒	☐	☐
S-37-26-6	☒	☒	MODIFICATION OF 126,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #3027: ADD LEAK DETECTION AND REPAIR CONDITIONS FOR RULE 4623 COMPLIANCE	OP		☒	☐	☐
S-37-27-5	☐	☐	37,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#37000) VENTED TO VAPOR RECOVERY SYSTEM LISTED ON TANK S-37-130 (#74000)	OP		☒	☐	☐
S-37-28-6	☐	☐	80,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#80000) VENTED TO VAPOR RECOVERY SYSTEM LISTED ON TANK S-37-130	OP		☒	☐	☐
S-37-31-8	☐	☐	1,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#1000) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-34-6	☒	☐	MODIFICATION OF 80,000 BBL EXTERNAL FLOATING ROOF PETROLEUM STORAGE TANK (#80,001), WELDED CONSTRUCTION WITH METALLIC SHOE PRIMARY SEAL AND SECONDARY RIM-MOUNTED SEAL: CONVERT TO FIXED ROOF AND CONNECT TO VAPOR RECOVERY SYSTEM LISTED UNDER PERMIT S-37-130			☐	☐	☐
S-37-34-7	☐	☐	80,000 BBL EXTERNAL FLOATING ROOF PETROLEUM STORAGE TANK (#80,001), WELDED CONSTRUCTION WITH METALLIC SHOE PRIMARY SEAL AND SECONDARY RIM-MOUNTED SEAL	OP		☒	☐	☐
S-37-38-13	☐	☐	TRANSMIX UNIT INCLUDING DISTILLATION COLUMNS, CONDENSERS, DRUMS, EXCHANGERS, PUMPS, REBOILERS, 3.75 MMBTU/HR GAS-FIRED FIRE TUBE HEATER (H-1), 3.67 MMBTU/HR GAS-FIRED HEATER (H-2) AND ASSOCIATED PIPING AND COMPONENTS	OP		☐	☒	☐
S-37-42-5	☐	☐	3,600 BBL ORGANIC LIQUID STORAGE TANK (#3300) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-43-5	☐	☐	15 HP LIGHT SOLVENT TRUCK LOADING OPERATION WITH VAPOR CONTROL SYSTEM INCLUDING: EMCO WHEATON LOADING HOSE AND VAPOR RETURN COUPLERS, 15 PUMP, METER AND CHECK VALVES AND VAPOR RETURN PIPING TO VAPOR CONTROL SYSTEM (RACK G)	OP		☒	☐	☐
S-37-44-5	☐	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3019) SERVED BY VAPOR RECOVERY SYSTEM LISTED ON PERMIT UNIT S-37-8		OOS	☒	☐	☐
S-37-46-7	☐	☐	30 HP LIQUID LOADING/UNLOADING OPERATION INCLUDING ONE UNCONTROLLED LIQUID LOADOUT LINE, ONE ORGANIC LIQUID LOADOUT/UNLOAD (TRANSFER) LINE EQUIPPED WITH VAPOR RECOVERY, TWO 15 HP PUMPS, DRY-BREAK CONNECTORS, METER(S), AND CHECK VALVES (RACK Q)	OP		☒	☐	☐
S-37-48-5	☐	☐	5,400 BBL ORGANIC LIQUID STORAGE TANK (#5014) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)		OOS	☒	☐	☐
S-37-49-5	☐	☐	5,400 BBL ORGANIC LIQUID STORAGE TANK (#5015) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-50-6	☐	☐	1,000 BBL ORGANIC LIQUID STORAGE TANK (#1100) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-51-6	☐	☐	20,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#20001) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-52-7	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10000) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-53-6	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10002) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-56-5	☐	☐	500 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#505) WITH A SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT UNIT S-37-8	OP		☒	☐	☐
S-37-57-8	☐	☐	210,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK #5017 WITH SHARED VAPOR RECOVERY SYSTEM LISTED IN S-37-8 AND 29 HP CIRCULATION PUMP WITH CLAY FILTER	OP		☒	☐	☐

S-37-58-4	☐	☐	29 HP JP-4 TRUCK LOADING OPERATION INCLUDING TWO EMCO WHEATON API STYLE DRYBREAK BOTTOM LOADING COUPLERS AND HOSES, TWO OPW MODEL 633 VAPOR RECOVERY COUPLERS AND VAPOR RETURN HOSES, 29 HP UNLOADING PUMP, FILTER, AND METER AND CHECK VALVES (RACK H)	OP		☒	☐	☐
S-37-59-6	☐	☐	20,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#20000) WITH A SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT UNIT S-37-8	OP		☒	☐	☐
S-37-61-8	☐	☐	800 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#800) WITH A SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT UNIT S-37-8	OP		☒	☐	☐
S-37-65-6	☐	☐	250 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#250, DEHY NORTH) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-66-6	☐	☐	250 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#251, DEHY SOUTH) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-67-5	☐	☐	8,400 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#200) WITH VAREC P/R VALVE, 1 HP PUMP, AND TRUCK UNLOADING FILL LINE WITH DRY-BREAK COUPLER (RACK T)		OOS	☒	☐	☐
S-37-71-7	☐	☐	ORGANIC LIQUID TRUCK LOADING/UNLOADING OPERATION INCLUDING TRUCK UNLOADING CONNECTION, TRUCK LOADING HOSE WITH DRY BREAK COUPLER, VAPOR RECOVERY HOSE WITH DRY BREAK CONNECTOR AND PIPING TO PERMITTED TANKS S-37-50 AND S-37-56 (RACK E)	OP		☒	☐	☐
S-37-77-19	☒	☒	MODIFICATION OF 36 MMBTU/HR DIESEL HYDROTREATER UNIT INCLUDING A 18 MMBTU/HR CHARGE HEATER WITH ZEECO INCORPORATED MODEL GLSF-11 FREE JET BURNERS, 18 MMBTU/HR STRIPPER HEATER WITH A CALLIDUS LE-CSG LOW NOX BURNER, HYDROGEN REACTOR VESSEL, HYDROGEN RECYCLE GAS SCRUBBER, AND ASSOCIATED PIPING AND COMPONENTS: REPLACE TWO HYDROGEN REACTORS			☐	☐	☐
S-37-77-21	☐	☐	36 MMBTU/HR DIESEL HYDROTREATER UNIT INCLUDING A 18 MMBTU/HR CHARGE HEATER WITH ZEECO INCORPORATED MODEL GLSF-11 FREE JET BURNERS, 18 MMBTU/HR STRIPPER HEATER WITH A CALLIDUS LE-CSG LOW NOX BURNER, HYDROGEN REACTOR VESSEL, HYDROGEN RECYCLE GAS SCRUBBER, AND ASSOCIATED PIPING, COMPONENTS, AND COMPRESSOR	OP		☒	☐	☐
S-37-78-5	☐	☐	SULFUR SCRUBBING SYSTEM INCLUDING MEA/DEA CONTACTOR VESSEL (ABSORBER), GAS LIQUID SEPARATOR, AMINE REGENERATION VESSEL, LIQUID SOLID SEPARATOR, SULFUR FILTER, AND ASSOCIATED AIR BLOWERS, PUMPS AND PIPING	OP		☒	☐	☐
S-37-79-5	☐	☐	14,700 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#335) CONNECTED TO VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-80-4	☐	☐	471 BHP DETROIT MODEL 12V71T DIESEL FIRED IC ENGINE DRIVING AN EMERGENCY GENERATOR	SB		☒	☐	☐
S-37-81-4	☐	☐	225 HP CUMMINS MODEL NT855F1 DIESEL FIRED IC ENGINE DRIVING AN EMERGENCY FIREWATER PUMP	OP		☒	☐	☐
S-37-82-5	☐	☐	60 BHP WAUKESHA MODEL 135 GZU-15861-G GAS-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN INSTRUMENT AIR COMPRESSOR		ABND	☒	☐	☐
S-37-83-5	☐	☐	150 BHP WAUKESHA MODEL 6 WAKB-10F GAS-FIRED EMERGENCY STANDBY IC ENGINE POWERING A UTILITY AIR COMPRESSOR	SB		☒	☐	☐
S-37-90-6	☐	☐	2,500 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#2501) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-91-7	☐	☐	2,500 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#2502) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-93-5	☐	☐	TRUCK LOADING RACK (RACK C), INCLUDING 6 ORGANIC LIQUID LOADING SPOTS	OP		☒	☐	☐
S-37-94-8	☐	☐	RAILCAR LIQUID TRANSFER FACILITY INCLUDING 48 ORGANIC LIQUID TRANSFER HOSES, 6 BUTANE TRANSFER HOSES, 8 TRANSFER PUMPS, AND 1 TRANSFER COMPRESSOR (RACK W)	OP		☐	☒	☐
S-37-95-9	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10003) VENTING TO A 2,000 LB CARBON CANISTER (SHARED WITH PERMIT UNIT S-37-96)		OOS	☒	☐	☐
S-37-96-8	☐	☐	10,000 BBL FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10004) VENTING TO A 2,000 LB CARBON CANISTER (SHARED WITH PERMIT UNIT S-37-95)		OOS	☒	☐	☐
S-37-97-6	☐	☐	3,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#3012) WITH A VAPOR CONTROL SYSTEM (LISTED ON PERMIT UNIT S-37-8)	SB		☒	☐	☐
S-37-102-7	☐	☐	10,000 BBL (420,000 GALLON) FIXED ROOF ORGANIC LIQUID STORAGE TANK #10005 SERVED BY VAPOR CONTROL SYSTEM LISTED ON PTO S-37-8	OP		☒	☐	☐
S-37-107-5	☐	☐	LPG, NATURAL GASOLINE, & MIXED LIGHT HYDROCARBON LOADING/UNLOADING RACK (RACK V) WITH VAPOR COLLECTION SYSTEM SERVING TANKS S-37-108 & -109	OP		☐	☒	☐
S-37-108-4	☐	☐	5,000 BBL SPHERICAL PRESSURE VESSEL STORING LPG, NATURAL GASOLINE, OR MIXED LIGHT HYDROCARBONS (TANK S-5000, EAST SPHERE)	OP		☒	☐	☐
S-37-109-4	☐	☐	5,000 BBL SPHERICAL PRESSURE VESSEL STORING LPG, NATURAL GASOLINE, OR MIXED LIGHT HYDROCARBONS (TANK S-5001, WEST SPHERE)	OP		☒	☐	☐
S-37-111-8	☒	☐	MODIFICATION OF 55,000 BBL ORGANIC LIQUID INTERNAL FLOATING ROOF TANK (#55000), WELDED CONSTRUCTION WITH MECHANICAL SHOE PRIMARY SEAL AND RIM-MOUNTED SECONDARY SEAL: CONVERT TO FIXED ROOF AND CONNECT TO VAPOR RECOVERY SYSTEM LISTED ON TANK S-37-166 (#12002)			☐	☐	☐
S-37-111-9	☐	☐	55,000 BBL ORGANIC LIQUID INTERNAL FLOATING ROOF TANK (#55000), WELDED CONSTRUCTION WITH MECHANICAL SHOE PRIMARY SEAL AND RIM-MOUNTED SECONDARY SEAL	OP		☒	☐	☐
S-37-114-8	☐	☐	SOLAR TARUS 60-7901S COGENERATION SYSTEM WITH NATURAL GAS FIRED TURBINE WITH DRY LOW NOX COMBUSTORS POWERING A 5.5 MEGAWATT ELECTRICAL GENERATOR, 23 MMBTU/HR NATURAL GAS FIRED DUCT BURNER, HEAT RECOVERY STEAM GENERATOR, SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND OXIDATION CATALYST	OP		☒	☐	☐
S-37-116-7	☐	☐	14.1 MMBTU/HR SPLITTER REBOILER HEATER SERVING PERMIT UNIT S-37-4	OP		☒	☐	☐

S-37-118-6	☐	☐	NAPHTHA FEED PRETREATMENT UNIT (NAPHTHA HYDROTREATER) WITH 12.6 MMBTU/HR CHARGE HEATER WITH JOHN ZINK COOLSTAR LOW NOX BURNER, 11.1 MMBTU/HR STRIPPER REBOILER HEATER WITH JOHN ZINK COOLSTAR LOW NOX BURNER, REACTOR VESSEL, HYDROGEN COMPRESSORS, HEAT EXCHANGERS, AND ASSOCIATED SEPARATOR VESSELS, KNOCKOUTS, PIPING, AND COMPONENTS AND COMPRESSOR POWERED BY IC ENGINE S-37-164	OP		☒	☐	☐
S-37-119-8	☐	☐	MODIFICATION OF NAPHTHA REFORMER UNIT WITH 25.7 MMBTU/HR CHARGE HEATER #1 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 13.4 MMBTU/HR CHARGE HEATER #2 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 8.9 MMBTU/HR CHARGE HEATER #3 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 8.3 MMBTU/HR SPLITTER/STABILIZER HEATER WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, REACTOR VESSELS, HYDROGEN COMPRESSORS, HEAT EXCHANGERS, AND ASSOCIATED SEPARATOR VESSELS, KNOCKOUTS, PIPING, AND COMPONENTS: REPLACE ONE STEAM DRIVEN COMPRESSOR WITH ONE ELECTRIC COMPRESSOR AND ONE ELECTRIC COMPRESSOR WITH ONE IC ENGINE DRIVEN COMPRESSOR S-37-165	OP		☒	☐	☐
S-37-119-9	☒	☐	MODIFICATION OF MODIFICATION OF NAPHTHA REFORMER UNIT WITH 25.7 MMBTU/HR CHARGE HEATER #1 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 13.4 MMBTU/HR CHARGE HEATER #2 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 8.9 MMBTU/HR CHARGE HEATER #3 WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, 8.3 MMBTU/HR SPLITTER/STABILIZER HEATER WITH JOHN ZINK SMR LOW NOX BURNER OR EQUIVALENT, REACTOR VESSELS, HYDROGEN COMPRESSORS, HEAT EXCHANGERS, AND ASSOCIATED SEPARATOR VESSELS, KNOCKOUTS, PIPING, AND COMPONENTS: REPLACE ONE STEAM DRIVEN COMPRESSOR WITH ONE ELECTRIC COMPRESSOR AND ONE ELECTRIC COMPRESSOR WITH ONE IC ENGINE DRIVEN COMPRESSOR S-37-165:REPLACE 8.3 MMBTU/HR SPLITTER HEATER BURNER WITH 12.19 MMBTU/HR CLEARSIGN BURNER.			☐	☐	☐
S-37-120-4	☐	☐	AMINE SYSTEM WITH ABSORBER VESSELS, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS. TREATED VAPOR RECOVERY GAS USED AS FUEL GAS FOR PROCESS HEATERS OR FLARED IN S-37-7	OP		☒	☐	☐
S-37-121-5	☐	☐	SOUR WATER SYSTEM WITH TWO STRIPPER COLUMNS, STEAM REBOILER, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS	OP		☒	☐	☐
S-37-122-7	☒	☐	MODIFICATION OF CLAUS PROCESS SULFUR RECOVERY UNIT WITH REACTION FURNACE, THREE CONVERTER VESSELS, HYDROGENATION REACTOR, ENCLOSED SULFUR PIT WITH EDUCTOR VENT TO SULFUR PLANT, TAIL GAS TREATMENT UNIT INCLUDING AMINE SCRUBBING SYSTEM AND 2.5 MMBTU/HR INCINERATOR WITH JOHN ZINK VYD BURNER, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS: SHARE NEW AMINE REGENERATION UNIT LISTED ON S-37-152; SHARE EXISTING ENCLOSED SULFUR PIT LISTED ON THIS PERMIT WITH S-37-152; ESTABLISH SPECIFIC LIMITING CONDITIONS (SLC) FOR S-37-122 AND -152			☐	☐	☐
S-37-122-8	☐	☐	CLAUS PROCESS SULFUR RECOVERY UNIT WITH REACTION FURNACE, THREE CONVERTER VESSELS, HYDROGENATION REACTOR, ENCLOSED SULFUR PIT WITH EDUCTOR VENT TO SULFUR PLANT, TAIL GAS TREATMENT UNIT INCLUDING AMINE SCRUBBING SYSTEM AND 2.5 MMBTU/HR INCINERATOR WITH JOHN ZINK VYD BURNER OR EQUIVALENT, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS	OP		☒	☐	☐
S-37-123-4	☐	☐	481 HP CATERPILLAR DIESEL-FIRED EMERGENCY IC ENGINE MODEL 3408DITA POWERING AN EMERGENCY FIREWATER PUMP	SB		☒	☐	☐
S-37-125-4	☐	☐	3,000 BBL (126,000 GALLON) FIXED ROOF ORGANIC LIQUID STORAGE TANK, #3013, SERVED BY THE VAPOR CONTROL SYSTEM OPERATING UNDER PERMIT S-37-8	SB		☒	☐	☐
S-37-126-4	☐	☐	55,000 BBL ORGANIC LIQUID STORAGE TANK #55002 WITH VAPOR BALANCE RETURN LINE FROM ORGANIC LIQUID LOADING RACK VAPOR RETURN PIPING AND VENTED TO VAPOR CONTROL SYSTEM LISTED ON S-37-8	OP		☐	☒	☐
S-37-127-6	☐	☐	GASOLINE DISPENSING OPERATION WITH ONE 12,000 SPLIT (9,000 GALLONS GASOLINE/3,000 GALLONS DIESEL) STEEL TANK INSTITUTE FIREGUARD ABOVEGROUND STORAGE TANK SERVED BY OPW PHASE I ENHANCED VAPOR RECOVERY (EVR) SYSTEM (VR-401-C), STANDING LOSS CONTROL (VR-301-E), AND 1 FUELING POINT WITH 1 GASOLINE DISPENSING NOZZLE SERVED BY BALANCE PHASE II VAPOR RECOVERY SYSTEM (G-70-162-A)	OP		☐	☒	☐
S-37-130-5	☐	☐	74,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#74000) WITH VAPOR RECOVERY SYSTEM INCLUDING A COMPRESSOR SHARED WITH TANKS S-37-27, -28, -34, -131	OP		☒	☐	☐
S-37-131-4	☐	☐	74,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#74001) VENTED TO VAPOR RECOVERY SYSTEM LISTED ON TANK S-37-130	OP		☒	☐	☐
S-37-138-4	☐	☐	ORGANIC LIQUID TRANSFER FACILITY WITH FOUR TRANSFER RACKS (RACK X)	OP		☒	☐	☐
S-37-139-4	☐	☐	CRUDE OIL UNLOADING RACK (NORTH OF TANK #80000) WITH TWO UNLOADING STATIONS, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS - LANE 1 SOUTH (RACK AA)	OP		☐	☒	☐
S-37-140-4	☐	☐	CRUDE OIL UNLOADING RACK (NORTH OF TANK #80000) WITH TWO UNLOADING STATIONS, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS - LANE 2 MIDDLE (RACK AA)	OP		☒	☐	☐
S-37-141-4	☐	☐	ORGANIC LIQUID UNLOADING RACK NORTH OF TANK #80000 WITH TWO UNLOADING HOSES, TRANSFER PUMP, AND ASSOCIATED VALVES, FLANGES, AND THREADED CONNECTIONS - LANE 3 NORTH (RACK AA)	OP		☒	☐	☐
S-37-142-4	☐	☐	RESIDUAL OIL TRANSFER RACK (FROM TRUCKS TO REFINERY OR REVERSE) EAST OF TANK #10000, WITH TWO TRANSFER POINTS, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS (RACK U)	OP		☒	☐	☐
S-37-143-4	☐	☐	RESIDUAL OIL TRANSFER RACK (FROM TRUCKS TO REFINERY OR REVERSE) NORTHWEST OF TANK #10006, WITH ONE TRANSFER POINT, TRANSFER PUMP, AND ASSOCIATED HOSES, VALVES, FLANGES, AND THREADED CONNECTIONS (RACK Y)	OP		☒	☐	☐
S-37-147-2	☐	☐	ORGANIC LIQUID UNLOADING RACK (RACK S) - SOUTH OF DIESEL TANK FARM		OOS	☒	☐	☐

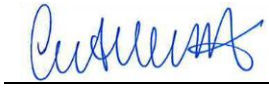
S-37-148-2	☐	☐	54,000 BBL EXTERNAL FLOATING ROOF ORGANIC LIQUID STORAGE TANK WITH EITHER A DUAL WIPER SEAL WITH DRIP CURTAIN OR PRIMARY METAL SHOE SEAL WITH SECONDARY WIPER SEAL	OP		☒	☐	☐
S-37-149-3	☐	☐	4 MMSCF/DAY LPG RECOVERY UNIT INCLUDING GAS COMPRESSION, MEMBRANE SEPARATION, REFRIGERATION, SOLID PHASE DRYING/ DEHYDRATION, AND FRACTIONATION	OP		☒	☐	☐
S-37-150-2	☐	☐	3000 BBL ORGANIC LIQUID STORAGE TANK VENTED TO VAPOR CONTROL SYSTEM LISTED ON S-37-8	OP		☒	☐	☐
S-37-152-0	☒	☒	CLAUS PROCESS SULFUR RECOVERY UNIT WITH REACTION FURNACE, THREE CONVERTER VESSELS, HYDROGENATION REACTOR, TAIL GAS TREATMENT UNIT, TAIL GAS AMINE SCRUBBING SYSTEM AND 1.9 MMBTU/HR INCINERATOR WITH ZEECO GB-8S BURNER OR EQUIVALENT, KNOCKOUTS, HEAT EXCHANGERS, CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) AND ASSOCIATED PIPING AND COMPONENTS, AND THE FOLLOWING EQUIPMENT SHARED WITH S-37-122: ENCLOSED SULFUR PIT WITH EDUCTOR VENT TO SULFUR PLANT AND AMINE REGENERATION UNIT	OP		☒	☐	☐
S-37-153-1	☐	☐	16,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (ID 16005) SERVED BY VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-154-1	☐	☐	16,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (16006) SERVED BY VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-155-1	☐	☐	ORGANIC LIQUID TRANSFER RACK R		OOS	☒	☐	☐
S-37-157-1	☐	☐	240 HP WAUKESHA MODEL F18G, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) DRIVING RECYCLE COMPRESSOR UNIT SERVING THE DIESEL HYDROTREATER (S-37-37)	OP		☒	☐	☐
S-37-158-1	☐	☐	27.6 MMBTU/HR CLEAVER BROOKS MODEL CBLE 700-800-250ST NATURAL GAS-FIRED FORCED AIR BOILER WITH A CLEAVER BROOKS ULTRA LOW NOX BURNER	OP		☒	☐	☐
S-37-159-1	☐	☐	310 HP WAUKESHA MODEL F18SE NATURAL GAS-FIRED IC ENGINE WITH NON-SELECTIVE CATALYTIC REDUCTION SERVING THE NORTH HYDROGEN COMPRESSOR AT THE PLATFORMER UNIT (S-37-4)	SB		☒	☐	☐
S-37-160-1	☐	☐	310 HP WAUKESHA MODEL F18SE NATURAL GAS-FIRED IC ENGINE WITH NON-SELECTIVE CATALYTIC REDUCTION SERVING THE #1 HYDROGEN COMPRESSOR- SOUTH, AT THE PLATFORMER UNIT (S-37-4)	OP		☒	☐	☐
S-37-161-1	☐	☐	310 HP WAUKESHA MODEL F18SE NATURAL GAS-FIRED IC ENGINE WITH NON-SELECTIVE CATALYTIC REDUCTION SERVING THE WEST HYDROGEN COMPRESSOR AT THE UNIFIER UNIT (S-37-3)	SB		☒	☐	☐
S-37-163-1	☐	☐	310 HP WAUKESHA MODEL MODEL F18SE, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) SERVING THE EAST HYDROGEN COMPRESSOR AT THE KHT UNIT (#S-37-3)	OP		☒	☐	☐
S-37-164-1	☐	☐	310 HP WAUKESHA MODEL MODEL F18SE, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) SERVING NAPHTHA HYDROTREATER RECYCLE COMPRESSOR (#S-37-118)	OP		☐	☒	☐
S-37-165-1	☐	☐	310 HP WAUKESHA MODEL MODEL F18SE, NATURAL GAS-FIRED IC ENGINE EQUIPPED WITH NONSELECTIVE CATALYTIC REDUCTION (NSCR) SERVING NAPHTHA REFORMER RECYCLE COMPRESSOR (#S-37-118)	OP		☐	☒	☐
S-37-166-0	☒	☐	12,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#12002) WITH VAPOR RECOVERY SYSTEM INCLUDING A COMPRESSOR SHARED WITH TANKS S-37-111, -167 (RENEW ONE TIME)			☐	☐	☐
S-37-167-0	☒	☐	12,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#12003 VENTED TO VAPOR RECOVERY SYSTEM LISTED ON TANK S-37-166 (#12002) (RENEW ONE TIME)			☐	☐	☐
S-37-169-0	☐	☐	AMINE SYSTEM NO.2 WITH ABSORBER VESSELS, KNOCKOUTS, HEAT EXCHANGERS, AND ASSOCIATED PIPING AND COMPONENTS WITH TREATED VAPOR RECOVERY GAS USED AS FUEL GAS FOR PROCESS HEATERS OR FLARED IN S-37-7	OP		☒	☐	☐
S-37-171-0	☐	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3016) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-172-0	☐	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3017) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-173-0	☐	☐	126,000 GALLON ORGANIC LIQUID STORAGE TANK (#3018) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8)	OP		☒	☐	☐
S-37-174-1	☐	☐	504,000 GALLON FIXED ROOF TANK (#12001) WITH VAPOR CONTROL SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-175-0	☒	☒	5,000 BBL ORGANIC LIQUID STORAGE TANK (#5013) SERVED BY SHARED VAPOR RECOVERY SYSTEM LISTED ON PERMIT S-37-8	OP		☒	☐	☐
S-37-176-0	☒	☐	3,000 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#3012) SERVED BY VAPOR CONTROL SYSTEM LISTED ON PERMIT UNIT S-37-8			☐	☐	☐
S-37-177-0	☒	☐	5,400 BBL FIXED ROOF ORGANIC LIQUID STORAGE TANK (#5014) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8) (REPLACEMENT FOR S-37-48)			☐	☐	☐
S-37-178-0	☒	☐	HYDROGEN RECOVERY UNIT CONSISTING OF HYDROGENATION, DEHYDROGENATION, AND HYDROGEN PURIFICATION EQUIPMENT INCLUDING REACTORS, COMPRESSORS, HEAT EXCHANGERS, PUMPS, MISCELLANEOUS VESSELS, AND 7 PERMIT EXEMPT HYDROGEN FUEL CELLS			☐	☐	☐
S-37-179-0	☒	☐	420,000 GALLON FIXED-ROOF ORGANIC LIQUID STORAGE TANK (#10001) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8) (REPLACEMENT FOR S-37-20)			☐	☐	☐
S-37-180-0	☒	☐	3,000 BBL (126,000 GALLON) FIXED ROOF ORGANIC LIQUID STORAGE TANK (#3013) WITH A SHARED VAPOR RECOVERY SYSTEM (LISTED ON PERMIT UNIT S-37-8) (REPLACEMENT FOR S-37-125)			☐	☐	☐

(COMPLETE THE FOLLOWING AS IT APPLIES TO THIS SOURCE)		COMPLIANCE		
		YES	NO	N/A
VARIANCE STATUS	On schedule: In compliance with all conditions:	☐	☐	☒
SOURCE TEST STATUS	Required: YES Performed: YES Excess Emissions: NO	☒	☐	☐
ATC(s) / PTO(s)	Accurate/Current: YES On site: YES Unpermitted Equip: NO Unimplemented: NO	☒	☐	
OPERATING SCHEDULE	Equipment hours comply with ATC/PTO? YES	☒	☐	☐
COMPLAINTS	Are there outstanding complaints against facility? No	☒	☐	
V.E. EVALUATION(s)	Conducted: YES In compliance with visible emission standard: YES	☒	☐	
RECORDS	Maintained: YES Records show compliance: YES	☒	☐	☐
	Meets permit limit for process rates: YES	☒	☐	☐
PORTABLE ANALYZER	Analyzer check shows emissions in compliance with limits:	☐	☒	☐
	Analyzer demonstrated to be in compliance with leak requirements:	☒	☐	☐
CEMS/ OTHER	Proper Maintenance / Calibration Procedures:	☒	☐	☐
MONITORING EQUIP	Have all reports been submitted on time and as required:	☒	☐	☐
BREAKDOWNS	Are there outstanding breakdowns:	☒	☐	☐
HEALTHY AIR LIVING	HAL information discussed with appropriate representative:	☐	☐	☒

ENFORCEMENT ACTION TAKEN: ☐NTC(s) ☒NOV(s) ☐RCAT(s) Number(s)

INSPECTION FREQUENCY | Modified as result of emission violation or nuisance: Frequency changed to: Months.

COMMENTS:

INSPECTOR SIGNATURE:  DATE: 08/24/26 REVIEWER: Steve Miller DATE: 09/14/26

ADDITIONAL INSPECTION COMMENTS

Reviewed 2025 records.

Authority To Construct (ATC)s:

ATC(s) converted to Permit To Operate (PTO)

- -21-14: change order S18332
- -22-14: change order S18333
- -25-6: change order S18334
- -26-6: change order S18336
- -152-0: change order S18337

Finalized ATC(s), but not ready to be converted:

- -166-0
- -167-0
- -176-0
- -177-0
- -178-0
- -179-0
- -180-0

COGEN

-6-20: Non-compliant DEU. Facility will retain permit active.

-114-8 Solar Tarus 60-7901S Cogen System:

- Unit is fueled by PUC natural gas only. Facility provided vendor's test data (from SoCal) consistent with the natural gas fuel sulfur content. Sulfur daily average was 0.18-grain/100 scf. (*Limit: 1.0 grains of sulfur compounds per 100 dry scf of natural gas*).
- Daily heat input to the gas turbine engine and duct burner are within limits. Highest noted was 236.9 MMBtu (228.49 mscfd) on 2/6/25 (*limit: 2,032.8 MMBtu/day*).
- Weekly records of the exhaust gas concentration of NOx *(limit: 2.5ppmvd)* (as NO2), CO (*limit: 6.0ppmvd @15% O2*), are maintained and compliant. Testing is conducted weekly.
- Monthly records of the date and time of all NOx, CO, and O2 measurements, the measured NO2 and CO concentrations corrected to 15% O2, and the O2 concentration; and records shall also include a description of any corrective action taken are maintained and in compliance. Unit is tested once a week. Test results within limits.
- Unit was tested at the time of inspection. Test results were within limits: *NOx: 0.6ppm; CO: zero; O2: 15.32%*
- Records of daily and rolling twelve-month natural gas consumption (MMBtu) of gas turbine engine and duct burner are maintained and in compliance. 2025 total SoCal fuel usage was 405.8 MMscf and Natural Gas HHV 1000 Btu/scf.
- Daily and rolling twelve month calculated emissions are maintained and in compliance, as follows: NOx 0.29 tons/yr.; VOC 0.15 tons/yr.; SOx 0.69 tons/yr.; CO 0.00 tons/yr.; PM10 1.40 tons/yr.; NH3 5,521 lbs./Yr. Ammonia Injection Rate: Highest noted at 26.65lbs on 5/9/25, and catalyst inlet temperature, highest noted at 661F on 1/23/25.
- 2025 total hours of operations were 8,311 hours.
- Last Source Test was conducted on 10/05/25 (Testing is required yearly), in compliance.

Emergency Engines

40 CFR 63 subpart JJJJ and ZZZZ are maintained and in compliance.

- -80-4: Total hours operated in 2025: 16.4 hours (*limit: 20 hrs./yr.*). No emergency hours recorded.
- -81-4: Total hours operated in 2025: 43.9 hours (*limit:100 hrs./yr.*). No emergency hours recorded.
- -82-5: Engine was removed and replaced with an electric engine in 2018. Facility will maintain permit active.
- -83-5: Total hours operated in 2025: 0.2 hours (*limit: 100 hrs./yr.*) No emergency hours recorded.
- -123-4: Total hours operated in 202: 51.3 hours (*limit: 100 hrs./yr.*). No emergency hours recorded.

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Fired Equipment

PTO -1-18:

- Records of total daily and annual duration of startup and shutdown times are maintained and in compliance. Startup and shutdown times were below limits. Tulsa Highest startup hours was 8 hours on 1/19/25 and highest shutdown hours was 4.42 hours on 2/22/25. Born highest startup hours was 8 hours on 1/19/25 and shutdown hours was 4.42 hours on 2/22/25. (*Born & Tulsa Heaters limit: 9.7 Startup hrs. and 6.2 shutdown hrs. respectively*).Tulsa heater 2025 total startup and shutdown hours were 43.93 hours. Born heater 2025 total startup and shutdown hours were 40.73 hours (*limit: 48.3 hrs./yr. for each unit*).
- Both units were tested at the time of inspection. Test results noted in supplemental inspection report.
- 2025 annual average heat input for Born heater was 55.1MMBtu/hr. and annual average heat input for Tulsa Heater was 34.2 MMBtu/hr. (*Limit: 60MMBtu/hr. as measured on an annual average basis, for each heater*).
- Heaters' stack concentrations of NOx, CO and O2 are tested monthly. Records are maintained and in compliance (*limits: Tulsa Heater NOx:9ppm CO: 150ppm O2: 3% and Born heater NOx:15ppm, CO: 150ppm at 3% O2*).
- H2S is monitored through District's CEMS
- Born heater Source Test was conducted on 4/25/2025 (ST is due every 36-months).
- Tulsa heater Source Test was conducted on 12/6/2024 (ST is due every 36-months).
- 2025 Quarterly LDAR records are maintained and in compliance.

PTO -2-10: Out of Service all of 2025.

PTO -3-11 KHT:

- Unit's stack concentrations of NOx, CO and O2 are tested monthly. Records are maintained and in compliance (*limits NOx: 25ppm; CO: 50ppm; O2: 3%*)
- Charge Heater and Splitter Reboiler Heater were tested at the time of inspection. Test results noted in supplemental inspection form.
- Records of startup and shutdown periods are maintained and in compliance. (*Limits:12 hours and 9 hours respectively*). Facility only records startup and shutdown hours if the unit exceeds the limits, otherwise they are zeroed out.
    - Charge Heater exceedance of startup period on 01/09/25—NOV.
- Splitter Reboiler and Charger heaters Source Tests were conducted on 2/12/25 (ST is due every 36-months), compliant.
- Sulfur analysis of fuel combusted is monitored through CEMS.
- 2025 Quarterly LDAR records are maintained and in compliance.

PTO -4-20 Platformer:

- Unit's stack concentrations of NOx, CO and O2 are tested monthly. Records are maintained and in compliance (*limits NOx: 25ppm; CO: 50ppm; O2: 3%*).
- Charge heaters #1, #2, and #3 were tested at the time of inspection. Test results noted in supplemental inspection form.
- Records of startup and shutdown periods are maintained and in compliance. (*Limits: 12 hours and 9 hours respectively*).
- Charger Heater #1, #2 and #3 Source Test was conducted on 02/06/25 (ST is due every 36-months), compliant.
- 2025 Quarterly LDAR records are maintained and in compliance.

-116: Splitter Reboiler Heater (Platformer):

- Unit's stack concentrations of NOx, CO and O2 are tested monthly. Records are maintained and in compliance (*limits: NOx (as NO2): 30 ppmv @3% O2; CO: 239 ppmvd @ 3% O2*).
- Daily records of amount and type(s) of fuel(s) combusted are maintained and in compliance. Highest observed was 280.98 Mscf or 280,890 scf on 12/12/25 (*limit: 338,000 scf/day*).
- Unit was tested at the time of inspection. Test results noted in supplemental inspection form.
- Records of startup and shutdown periods are maintained and in compliance (*Limit: 8.5 hours and 5.6 hours respectively*).
    - Unit exceeded shutdown period on 1/9/25—NOV.
- Unit's Source Test was conducted on 2/26/24 (ST is due every 36-months), compliant.
- 2025 Quarterly LDAR records for all units are maintained and in compliance.

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PTO -38 Transmix Unit:

- Daily sulfur content (H2S) of refinery fuel is monitored through CEMS (*limit H2S>162ppm on a 3-hour rolling average basis*)
- H-1 and H-2 stack concentrations of NOx, CO and O2 are tested monthly. Records are maintained and in compliance. (*Limit: 30 ppmvd NOx @ 3% O2, 400 ppmvd CO @ 3% O2*).
- Units were tested at the time of inspection. Test results noted in supplemental inspection form.
- Records of startup and shutdown periods are maintained and in compliance.
    - H-1 exceeded startup period on 1/19/25; and exceeded shutdown period on 1/12/25; 2/23/25, 3/15/25, 3/23/25—NOV.
    - H-2 exceeded startup period on 1/20/25, 4/12/25; and exceeded shutdown period on 2/23/25, 3/23/25, 4/7/25, 4/9/25—NOV.
- 2025 Quarterly LDAR records are maintained and in compliance.

PTOs -77: Diesel Hydrotreater Unit (DHT):

- Charge and Stripper Heaters stack concentrations of NOx, CO and O2 are tested monthly. Records are maintained and in compliance (*limits NOx (as NO2): 25 ppmv @ 3% O2, CO: 50 ppmv @ 3% O2*).
- Units were tested at the time of inspection. Test results noted in supplemental inspection form.
- Records of startup and shutdown periods are maintained and in compliance (*Limits: for reactor process heater H1,12.0 hours and 9.0 hours each, respectively and startup and shutdown period for reboiler heater H2 12.0 hours and 5.0 hours, respectively*).
- Charge heater Source Test was conducted on 4/7/25 (ST is due every 36-months), compliant.
- Stripper heater Source Test was conducted on 4/28/25 (ST is due every 36-months), compliant.
- 2025 Quarterly LDAR records for all units are maintained and in compliance.

-118: Naphtha Hydrotreater (NHT):

- Charge and Reboiler were tested monthly. Records of monthly monitoring records of stack concentration of NOx, CO and O2, for each heater; are maintained and in compliance. (*limits NOx (as NO2): 25 ppmv @ 3% O2, CO: 150 ppmv @ 3% O2*).
- Units were tested at the time of inspection. Test results noted in supplemental inspection form.
- Records of startup and shutdown periods are maintained and in compliance. (*limits: Startup and shutdown period for the charge heater shall not exceed 12.0 hours and 5.8 hours respectively; and startup and shutdown period for the reboiler heater shall not exceed 12.0 hours and 5.0 hours respectively*).
- H2S is monitored through District's CEMS
- Charge heater Source Test was conducted on 4/7/25 (ST is due every 36-months), compliant.
- Reboiler heater Source Test was conducted on 4/24/25 (ST is due every 36-months), compliant.
- 2025 Quarterly LDAR records for all units are maintained and in compliance.

-119: Naphtha Reformer Unit:

- All units are tested monthly. Records of monthly monitoring records of stack concentration of NOx, CO and O2, for each heater; are maintained and in compliance. (*limits NOx (as NO2): 25 ppmv @ 3% O2, VOC: 0.0055 lb./MMBtu, or CO: 150 ppmv @ 3% O2*)
- All operating units were tested at the time of inspection. Test results noted in supplemental inspection report.
- Records of startup and shutdown hours are maintained and in compliance (*limit: startup and shutdown period for 25.7 MMBtu/hr. Charge Heater #1, 13.4 MMBtu/hr. Charge Heater #2, and 8.9 MMbtu/hr. Charge Heater #3 shall not exceed 12.0 hours and 9.0 hours each respectively. Startup and shutdown period for the Splitter/Stabilizer Heater shall not exceed 8.5 hours and 5.0 hours respectively*).
- 2025 Quarterly LDAR records for all units are maintained and in compliance.

PTO -122 SRU #1:

- Daily records of Sulfur production from Claus sulfur recovery plant are maintained and in compliance. Highest day noted was 6 long-tons (*limit: 20 long-tons/day combined with -152*).
- Daily and annual records of SOx emissions from incinerator exhaust are maintained and in compliance. Highest day noted was 122.2 lbs. on 9/16/25 during startup (*limit: during startup: 224.0 lb. SOx*) 2025 annual SOx emissions was 3,329.71 lbs./yr. (*Limit: 33.8lbs/day and 12,718 lbs./yr.*)
- Unit was tested at the time of inspections. Test results noted in supplemental inspection report.
- Sulfur analysis of fuel combusted is monitored through CEMS (limit H2S >100ppm)
- Records of Startup and shutdown periods are maintained and in compliance. No exceedances recorded. (*limit: 37.0 hours and 23.4 hours respectively*).
- Source Test was completed on 5/19/25, in compliance (annual testing).

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ATC -152 SRU #2:

- Operating schedule alternates with SRU#1. Unit last operated on 8/5/25; 9/21/25 through 10/2/25 and 12/11/25 through 12/31/25.
- Daily and annual records of SOx emissions from incinerator exhaust are maintained and in compliance Highest day noted was 33.6 lbs. on 12/13/25. 2025 annual SOx emissions were 597.42 lbs./yr. (*limit: 33.8lbs/day and yearly combined with -122: 13,166 lbs./yr.*) Highest startup exceedance recorded was 104.3 lbs. on 12/11/25 (*limit during startup: 224 lbs. SOx/day*)
- Unit uses SoCal gas fuel, and does not use FR gas.
- Source Test was conducted on 2/18/26.

Annual records of heat input (MMBtu/hr.) for **all fired equipment units** are maintained and in compliance. 887 MMBtu for each (*No limit*).

NG ENGINES

-157; 159; -160; -161; -163; -164; & -165:

- All units are tested monthly. Records of monthly monitoring records of stack concentration of NOx, CO and O2, for each engine; are maintained and in compliance.
- All units operating at the time of inspection were tested. Test results noted in NG engine supplemental report.
    - -164: NOx test results were within limits. CO results was 82ppm, exceeding the 56ppm limit—NOV. District retested unit on 5/13/26. Test result were compliant. NOx: 1.2ppm; CO: 14ppm (*limit: NOx: 5ppm; CO: 56ppm*).
    - -165: NOx test results were within limits. CO results was 378ppm, exceeding the 56ppm limit—NOV.
- Total hours of operation are maintained and in compliance. 2025 total operating hours: -157: 7,474 hours; -159: 5,491 hours. -160: 2,852.7 hours; -161: 6,402 hours. -163: hours; 1,763 hours; -164: 6,456 hours; -165: 8,092 hours.

-7 Flare and CEMS

- H2S is monitored through District's CEMS.
- 2025 Daily monitoring records of water level and pressure of water seal that services the flare are maintained and in compliance.
- 2025 annual Method 22 VEE was conducted on 4/3/25 from 2:00pm to 4:00pm by J. Gipson.
- 2025 Annual Flare Monitoring Report received 1/9/2026.
- 2025 annual throughput threshold was 5,769 MMBtu (limit: 25,000 MMBtu/yr.). 2025 compliant with District Rule 4311 section 5.9.

-127: GDF- done

- 2025 Gasoline throughput was 165,102 gallons (*limit: 518,344 gals./yr.*). Highest monthly observed was 366 bbl. in Sept. 2025.
- Weekly maintenance inspections are conducted. Records are maintained and in compliance.
- 2025 static leak test was completed on 6/6/25.

TANKS

-12; -13; -14; -15; -16; -18; -19; -20; -21; -22 -23; -24; -25; -26; -27; -28; -31; -34; -42; -48 -49; -50; -51; -52; -53; -56; -57; -59; -61; -65; -66; -67; -79; -90; -91; -95; -96; -97; -102; -108; -109; -111; -125; -126; -130; -131; -148; -150; -153; -154; -174.

- 2025 Quarterly LDAR records, maintained and in compliance.
- -21 and -22: Tanks are under Vapor Recovery System.
- -25: TVP at 0.3 psi at 100F. API gravity at 28.9 tested on 7/17/24.
- -27-5: fixed roof tank and connected to vapor recovery unit.
- -34: External Floating Roof tank. 2025 annual seal gap inspection occurred on 5/6/25. Compliant
- -61: Tank is under Vapor Recovery System.
- -44, -48, -67, -95 and -96: Out Of Service
- -126: three >10,000ppm gas-leak findings on tank's roof—NOV.
- -148:
    - TVP at 6.6 psi; Tested on 8/7/23
    - Daily throughput at 814 bbl./day based on a monthly average. 2025 annual total 296,998 bbl. (*limits: 25,000 bbl./day based on a monthly average. 3,125,860 bbl./yr.*).
    - Seal Gap test was conducted on 5/12/26. Seal gap test failed, repairs were conducted and reinspected on 5/27/26—NOV.

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TRANSFER RACKS:

- Findings at the time of inspection are noted on supplemental inspection report.

PTO -8: (Racks A, F, K, L, N)

- Drainage inspections are conducted once a month, compliant.
- 2025 throughput records maintained and in compliance (no limit)

PTO -43 (Rack G – truck loading operation)

- Drainage inspections are conducted once a month, compliant.
- There were zero disconnects in 2025.

PTO -46 (Rack Q – Liquid loading/unloading operation)

- Drainage inspections are conducted once a month, compliant.
- Daily loadout of liquids is maintained. 2025 total barrels of Diesel (transferred to tank 5030) was 5,962 bbl.; Ethanol (transferred to Tank 10002) was 506,589; total barrels of Transmix (transferred to Tank 5008) were 329,716 (*limit: Organic liquids with TVP >1.5 psi 28,000 gals/day*), compliant.
- Monthly results of leak inspections of the loading and vapor collection equipment at each loading arm are maintained and in compliance.

PTO -58 (Rack H – truck loading operation)

- Drainage inspections are conducted once a month, compliant.
- Monthly results of leak inspections of the loading and vapor collection equipment at each loading arm are maintained and in compliance.

PTO -67 Truck Unloading Fill Lane with Dry-Break Coupler (Rack T):

- Out of service.

PTO -71 (Rack E – truck loading/unloading operation)

- Daily throughput of liquid transferred are maintained.

PTO -93 (Rack C – Truck loading rack and 6 organic liquid loading)

- Type of liquid loaded is PS 1500 which has a TVP less than 1.5 psi.
- 2025 total liquid loaded was 2,875,790 bbl. (*no limit*).

PTO -94 (Rack W) Railcar liquid transfer facility

- Daily records of number of disconnects are maintained and in compliance. Highest observed was a total of 9.7 disconnects in the months of April and May. (*limit 144 disconnects/day*)
- Types of liquids/gases transferred are Ethanol, Alkylate, Toluene, Crude, B-100, GEEB, JC747, NG, Butane, Isocotone, Cetane, Transmix and EPA Diesel.

PTO -107 (Rack V) LPG, Natural Gasoline & Mixed light Hydrocarbon loading/unloading

- Daily number of disconnects are maintained and in compliance. Highest observed was a total of 127 disconnects in the month of December 2025 or daily average 4.11 disconnects/day. (*limit: 56 disconnects/day*).

PTO -138 (Rack X) Organic liquid transfer facility

- Daily records of volume of organic liquid transferred are maintained and in compliance. Highest noted was 965 gpd in February 2025 (*limit: 23,016 gal/day*).
- Per SDS, product's TVP is 0.00966 psi (*limit: TVP of liquids transferred shall not exceed 0.05psi at transfer temperature*)
- Type of liquids transferred was Kerosene K-1from tank 3021; JC747 from tanks 3022 and 3023.

PTO -139 Lane 1 South (Rack AA) Crude Oil Unloading Rack

- Daily records of unloading rack throughput are maintained and in compliance. Highest noted was 54,285 gal. in June 2025.
- Results of leak inspections are conducted and in compliance.

PTO -140 Lane 2 Middle (Rack AA) Crude Oil unloading Rack

- Daily records of unloading rack throughputs are maintained and in compliance. Highest noted was 28,052 gallons in the month of November 2025 (*no limit*).
- There were zero disconnects in 2024 (*limit 48 disconnects/day*). DISCONNECTS ARE ALL TOGETHER WITH -141
- Results of leak inspections are maintained an in compliance.

PTO -141 Lane 3 North (RACK AA)

- Daily records of unloading rack throughputs are maintained and in compliance. Highest noted was 3,366 in the month of January 2025. (*no limit*).
- Daily records of unloading disconnect are maintained and in compliance. Highest noted was 1.0 disconnects in the month of October 2025 (*limit: 48 disconnects/day*).

PTO -142 Residual Oil Transfer Rack (Rack U)

- 2025 not in use.

PTO -143: Residual Oil Transfer Rack (Rack Y)

- Product type: AGO

PTO -147 Organic Liquid Unloading Rack (Rack S)

- Daily records of unloading rack throughputs are maintained and in compliance. Highest noted 11,573 bbl. in March 2025 (*no limit*).
- Daily records of unloading disconnects are maintained and in compliance. Highest noted was 2 disconnects in the month of March 2025 (*limit 20 disconnects/day*).

PTO -155 (Rack R):

- Out of service.

WASTE WATER

-9 Oil/Water Separation Operation

- Annual VOC content test was conducted on 12/22/25. Total VOCs were below 10% by weight (ND).
- Hole on pit cover (Rule 4625 violation) – NOV.

TWO-YEAR ENFORCEMENT HISTORY						
TYPE	**NUMBER**	**OCCURRED**	**ISSUED**	**STATUS**	**CITATION**	**NATURE OF VIOLATION**
NOV	5033302	06/17/2024	**07/24/2024**	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv (06/17/24, 06/18/24, 06/19/24)
NOV	5033304	07/06/2024	07/24/2024	CLOSED	2070, 2201, 2520, 4623	Failure to maintain vapor recovery system in operation
NOV	5033343	03/03/2023	08/01/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv; Failure to submit Deviation Report within 10-days of discovery date.
NOV	5033434	12/05/2023	08/20/2024	CLOSED	2070, 2520, 4455	Exceedance of allowable leaks in Table 2 per Rule 4455: Valves; Threaded Connections; and Other components.
NOV	5033305	07/18/2024	08/28/2024	CLOSED	2070, 2201, 2520, 4301	Failure to comply with H2S limit of 100ppm: -1, -3, -4, -116 on 7-24-24 -77, -118, -119, -122 on 7-18-24, 7-24-24, and 7-26-24 and Failure to comply with H2S limit of 162ppm: -38 on 7-24-24
NOV	5033515	08/07/2024	09/03/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv (08/07/24, 08/08/24)
NOV	5033493	08/06/2024	09/03/2024	CLOSED	2070, 2201, 2520, 4301	Failure to comply with H2S limit of 100ppm
NOV	5033594	12/31/2023	09/17/2024	CLOSED	2201, 2520	Exceedance of annual average heat input
NOV	5033597	08/12/2022	09/17/2024	COMPLIANCE ACHIEVED	2201, 2520	Exceedance of True Vapor Pressure (TVP) limit of liquids transferred
NOV	5033599	09/02/2022	09/17/2024	CLOSED	2070, 2201, 2520	Exceedance of H2S limits
NOV	5033677	09/21/2024	10/01/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv
NOV	5033765	08/31/2023	10/16/2024	CLOSED	2070, 2201, 2520	Exceedance of H2S limits
NOV	5033766	11/09/2023	10/16/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv
NOV	5033846	10/21/2024	11/04/2024	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 10/21/24 and 10/25/24
NOV	5033850	10/22/2024	11/04/2024	CLOSED	2070, 2201, 2520, 4623	Failure to maintain secondary seal without holes, tears or openings.
NOV	5033980	11/12/2024	11/21/2024	COMPLIANCE ACHIEVED	2070, 2201, 2520, 4623, 4624	Discoveries found during District annual inspection include: I. Rule 4624: two greater than 1,000ppm gas- leaks. II. Rule 4623 one greater than 10,000ppm gas-leak.
NOV	5033983	11/14/2024	11/21/2024	COMPLIANCE ACHIEVED	2070, 2520, 4455	District Rule 4455 greater than 50,000ppm gas-leak at threaded connection
NOV	5034062	11/25/2024	12/02/2024	COMPLIANCE ACHIEVED	2070, 2201, 2520, 4624	Two greater than 1,000ppm gas-leak discovered during District annual inspection
NOV	5034095	12/03/2024	12/04/2024	CLOSED	2070, 2520, 4455	One gas-leaks greater than 50,000ppm at DHT compressor, discovered during District's annual inspection.
NOV	5034294	12/17/2024	12/20/2024	CLOSED	2201, 2520, 4306, 4702	Excess NOx emissions
NOV	5034297	12/17/2024	12/20/2024	COMPLIANCE ACHIEVED	2070, 2520, 4455	Greater than 50,000ppm gas-leak at threaded connection, discovered during District's annual inspection.
NOV	5034298	12/19/2024	12/20/2024	CLOSED	2070, 2201, 2520	Greater than 100ppm gas-leak at valve
NOV	5034357	12/16/2024	12/30/2024	CLOSED	2201, 2520, 4455, 4623, 4624	Failure to maintain vapor recovery system functional and operating
NOV	5034361	11/26/2024	01/29/2025	CLOSED	2010, 2070	Failure to maintain a functioning and operating vapor recovery system.
NOV	5034680	01/23/2025	02/04/2025	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 01/23/25
NOV	5034746	02/02/2025	02/11/2025	CLOSED	2070, 2520	Failure to comply with H2S limit of 162 ppmv on 02/02/25
NTC	5034232	06/19/2024	02/25/2025	CLOSED	2070, 4621, 4622	Failure to conduct and pass the required vapor recovery performance testing.
NTC	5034233	07/10/2024	02/25/2025	CLOSED	4622	Failure to submit an Authority to construct application to either comply with the phase II EVR requirements of VR-501-D by July 9, 2024 or by limiting the annual throughput of gasoline to 480,000 gallons.
NOV	5034823	06/15/2021	02/26/2025	COMPLIANCE ACHIEVED	2010, 2201, 2520	Second Notice of Violation: i. failure to source test within 60 days of startup ii. failure to certify CEMS unit
NOV	5034898	03/03/2025	04/02/2025	CLOSED	2070, 2201, 2520	Failure to comply with: Flare H2S limit of 162ppm on 3/3/25; and Fuel gas H2S limit of 84.5ppm on 3/24/25
NOV	5035031	03/25/2025	04/08/2025	CLOSED	2070, 2520	Failure to maintain CEMS
NOV	5035119	03/21/2024	05/01/2025	CLOSED	2070, 2520, 4306	Transmix H-1 Heater exceedance of startup period on 6/22/24 and 1/19/25; Transmix H-1 Heater exceedance of shutdown period on 2/23/25, 3/15/25, 3/23/25 and 1/12/25;

						Transmix H-2 Heater exceedance of startup period on 3/21/24, 3/31/24, 4/20/24, 1/20/25 and 4/12/25; Transmix H-2 Heater exceedance of shutdown period on 12/23/24, 2/23/25, 3/23/25, 4/7/25, and 4/9/25; KHT Charge Heater exceedance of startup period on 01/09/25; NHT Charge Heater exceedance of startup period on 1/20/25; and Platformer Splitter Reboiler Heater exceedance of shutdown period on 1/9/25.
NOV	5035226	04/03/2025	05/20/2025	CLOSED	2070, 2520	Failure to maintain operating flare and fuel gas CEMS on 4/3/25; Failure to comply with H2S limit of 84.5 ppm, 100ppm and 162 ppm on 04/20/25
NOV	5035388	05/15/2025	06/26/2025	CLOSED	2070, 2520	1. Visible excess emissions. 2. Failure to submit deviation report within 10-days.
NOV	5035277	05/20/2025	07/10/2025	CLOSED	2070, 4307	Transmix Heater H-1: Startup exceedance period on 6/9/2025; Transmix Heater H-2: Startup exceedance period on 6/4/2025 and 6/19/2025; Transmix Heater H-2: Shutdown exceedance period on 5/20/25.
NOV	5035527	03/08/2025	08/04/2025	CLOSED	2520	Failure to submit a deviation report within the specified time frame as required by permit S-37, 0-4 condition 11.
NOV	5035687	07/11/2025	09/10/2025	CLOSED	2070, 2520	Failure to maintain operating flare and fuel gas CEMS on 8/29/25; Failure to comply with H2S limit of 84.5 ppm on 7/11/25
NOV	5035903	09/16/2025	11/04/2025	COMPLIANCE ACHIEVED	2070, 2520	Failure to comply with H2S limit of 84.5 ppm on 9/16/25; Failure to comply with H2S limit of 84.5ppm on 10/7/25 & 10/18/25; and Failure to comply with H2S limit of 100ppm on a 3-hour rolling average on 10/7/25
NOV	5035986	11/07/2025	12/18/2025	COMPLIANCE ACHIEVED	2070, 2520	Failure to maintain operating flare and fuel gas CEMS from 11/7/25 to 11/10/25 and 11/13/25.
NOV	5036583	12/16/2025	01/05/2026	COMPLIANCE ACHIEVED	2070, 2520, 4623	Failure to maintain tank in a leak free conditions
NOV	5037573	07/14/2025	06/30/2026	COMPLIANCE ACHIEVED	2070, 4307	Transmix Heater H-1: Shutdown exceedance period 8/6/25. Transmix Heater H-2: Shutdown exceedance period on 7/14/25; 9/21/25; and 12/30/25.
NOV	5037574	01/06/2026	06/30/2026	NOV ISSUED	2201, 2520, 4306, 4702	Excess NOx emissions
RCAT	5035527	02/11/2026	07/15/2026	NOV ISSUED	1080, 2070	Failure to submit a protocol at least 15 days before testing.
NOV	5037846	02/26/2026	08/20/2026	NOV ISSUED	2070, 2520	Failure to comply with H2S limit of 84.5 ppm
NOV	5037848	03/23/2026	08/20/2026	NOV ISSUED	2070, 2520	Exceeded concentration of sulfur compounds in the exhaust
NOV	5037849	04/14/2026	08/20/2026	NOV ISSUED	2070, 2520	Exceeded SOx emissions of 33.8 lbs/day
NOV	5037850	04/28/2026	08/20/2026	NOV ISSUED	2070, 2520, 4623	Failure to maintain vapor recovery unit functional and operating
NOV	5037851	05/05/2026	08/20/2026	NOV ISSUED	2070, 2201, 2520, 4624, 4625	Discoveries during District annual inspection include: i. Rule 2201: one greater than 100ppm gas-leak; ii. Rule 4624: two greater than 1,000ppm gas- leaks. iii. Rule 4625: hole/opening on drain pit
NOV	5037853	05/06/2026	08/24/2026	NOV ISSUED	2070, 2201, 2520, 4623, 4624, 4702	Discoveries during District annual inspection include: i. Rule 2201 and 4702: NHT NG engine excess CO emissions limits; ii. Rule 2201 and 4702: Reformer NG engine excess CO emissions; iii. Rule 4623: three greater than 10,000ppm gas-leak on tank's roof. iv. Rule 4624: two greater than 1,000ppm gas- leaks at Rack W
NOV	5037854	05/12/2026	08/24/2026	NOV ISSUED	2070, 2520, 4623	Failed annual seal gap test
NOV	5037855	05/13/2026	08/24/2026	NOV ISSUED	2070, 2201, 2520, 4307, 4455, 4624	Discoveries during District annual inspection include: i. Rule 4455: one greater than 50,000ppm gas-leak at DHT drain on 5/13/26; ii. Rule 4624: one greater than 1,000ppm gas- leaks on 5/14/26; iii. Rule 2201 and 4307: H-1 heater excess NOx emissions on 5/14/26; iv. Rule 4455: one greater than 50,000ppm gas-leak at SRU#1 on 5/28/26
NOV	5037858	06/03/2026	08/24/2026	NOV ISSUED	2070, 2520, 4622	Failure to maintain the vapor recovery system. (Vapor hose.)

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit BOPD	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-12	5009	Gasoline Tank Farm	4700	Gasoline				Y	Y	Y		1/7/26
-13*	5010	Gasoline Tank Farm	5150	B5 or BlendStock				Y	Y	Y		1/7/26
-14*	5011	Gasoline Tank Farm	5000	Gasoline				Y	Y	Y		1/7/26
-15*	5020	Gasoline Tank Farm	5000	ISO-OCtane				Y	Y	Y		1/7/26
-16	12000	Gasoline Tank Farm	12000	OOS				Y	Y	N	OGI finding-Emergency hatch	1/7/26
-18	10007	Gasoline Tank Farm	10000	Gasoline				Y	Y	Y		1/7/26
-19	10008	Gasoline Tank Farm	10000	Gasoline				Y	Y	Y		1/7/26
-20	10001	Middle Tank Farm	10000	Alkylate				Y	Y	Y		1/6/26
-21	5006	South Tank Farm	5000	Unifinate				Y	Y	Y		1/6/26
-22	5007	South Tank Farm	5000	Unifinate				Y	Y	Y		1/6/26
-23	5008	South Tank Farm	5000	Transmix				Y	Y	Y		1/6/26
-24	3014	South Tank Farm	3000	Unifinate				Y	Y	Y		1/6/26
-25	3026	South Tank Farm	3000	Biodiesel (B-99)	0.3/0.5	7/17/24		Y	Y	N		1/6/26
-26	3027	South Tank Farm	3000	Biodiesel	0.3/0.5	7/17/24		Y	Y	N		1/6/26

Comments
Tanks were surveyed using OGI camera, emissions detected on accessible components, were quantified using a TVA.

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-9	5061	Water Treament Plant	5000	Produce Water								5/5/26
-9	5062	Water Treatment Plant	5000	Produce Water								5/5/26
-9	5063	Water Treatment Plant	5000	Produce Water								5/5/26
-27	37000	Crude Tank Farm	37000	Crude Oil	/11 under VPS	8/2/23		N	Y	Y		5/14/26
-28	80000	Crude Tank Farm	80000	Crude Oil				N	Y	Y		5/14/26
-31	1000	Gasoline Tank Farm	1000	Water/Oil				Y	Y	Y		1/7/26
-34	80001	Crude Tank Farm	80000	Crude Oil				Y	Y	Y		5/14/26
-42	3300	Gasoline Tank Farm	3600	Lt.Solvent				Y	Y	Y		1/7/26
-44	3019	South Tank Farm	3000	Sour Water				Y	Y	N	OOS	1/6/26
-48	5014	Gasoline Tank Farm	5400	OOS				Y	Y	Y	OOS	1/7/26
-49	5015	Gasoline Tank Farm	5400	LN Light Naptha				Y	Y	Y		1/7/26
-50	1100	Gasoline Tank Farm	1000	Vesta-Diesel Additive				Y	Y	Y		1/7/26
-51	20001	Diesel Tank Farm	20000	Carb Diesel				Y	Y	Y		5/6/26
-52	10000	Middle tank Farm	10000					Y	Y	Y		1/6/26
-53	10002	Middel Tank Farm	10000	TOL Toluene				Y	Y	Y	OGI-Inaccessible components/N&S hatch & PVRV	1/6/26
-56	505	Gasoline Tank Farm	500	Transmix				Y	Y	Y		1/7/26
-57	5017	Gasoline Tank Farm	5000	LN Light Naptha				Y	Y	Y		1/7/26
-59	20000	Diesel Tank Farm	20000	Carb Diesel				Y	Y	Y		5/6/26

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-61	800	Gasoline Tank Farm	800	Biodiesel (B99)				Y	Y	Y		1/7/26
-65	250	Dehy North	250	Oily Water				Y	Y	Y		1/6/26
-66	251	Dehy South	250	Oily water				Y	Y	Y		1/6/26
-67	200	OOS	200	Organic Liquid	/2.7		/2500	Y			OOS	
-79	335	Gasoline Tank Farm	350	Gsoline Additive				Y	Y	Y		1/7/26
-90	2501	Gasoline Tank Farm	2500	Light Platfomatee				Y	Y	Y		1/7/26
-91	2502	Gasoline TankFarm	2500	Light Platfomate				Y	Y	Y		1/7/26
-95	10003	Tracks Tank Farm	10000	Water				Y	Y	N	OOS	5/6/26
-96	10004	Tracks Tank Farm	10000	OOS				Y	Y	N	OOS	5/6/26
-97	3012	Middle Tank Farm	3000	SB				Y	Y	Y	SB-empty but not opened	1/6/26
-102	10005	Gasoline Tank Farm	10000	PLAT Heavy				Y	Y	Y		1/7/26
-108	S5000	LPG Storage	5000	Natural Gasoline				N	Y	N		5/5/26
-109	S5001	LPG Strorage	5000	Butane				N	Y	N		5/5/26
-111	55000	Tracks Tank Farm	55000	Crude oil				N	Y	N		5/6/26
-125	3013	Middle Tank Farm	3000	SB				N	N	N	Tank will be replaced with ATC-180	1/6/26

Comments: VM&P = Varnish, Mineral Spirits, and Paints

* Tank 200 is located @ end of solvent unit. This tank is used on the process side, possibly as a knockout. This tank historically held product that feed to a truck loadout, the loadout pump has been removed for years.

* Tank 335 – Vertical ladder does not have a cage, due to safety concerns this tank is not checked for leaks by District staff.

* Tank 800 – Tank holds Naphtha and has a vertical ladder. Must be connected to VR when TVP is >0.4psi; when TVP is ≤ 0.4psi VR may be removed. See PTO for throughput restrictions.

* PTOs -108-2 & -109-2 are spheres (pressurized vessels), they are inspected during the LDAR portion of Rule 4455. District Inspection subject to Rule 2201.

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
-126	55002	Diesel Tank Farm	55000	Hv. Distillate				Y	Y	Y	11200ppm/hole 12900ppm/hole 11800ppm/hole	5/6/26
-127	55001	Diesel Tank Farm	55000	TC topped Crude								5/6/26
-130	74000 & TVR	Crude Tank Farm	74000	Crude Oil			/ * See Permit	N	Y	Y		5/14/26
-131	74001	Crude Tank Farm	74001	Crude Oil			/ * See Permit	N	Y	Y		5/14/26
-148	54000	Tracks Tank Farm	54000	Crude Oil							OGI findings/Inaccessible components	5/6/26
-150	3015	South Tank Farm	3000	Unifinate				Y	Y	Y		1/6/26
-153	16005	Gasoline Tank Farm	17000	ETH Ethanol				Y	Y	Y		1/7/26
-154	16006	Gasoline Tank Farm	17000	PLAT Heavy Platformate				Y	Y	Y		1/7/26
ATC-166	12002		12000									
ATC-167	12003		12000									
-171	3016	South Tank Farm	3000	Renewable Diesel								1/6/26
-172	3017	South Tank Farm	3000	Renewable Diesel (R99)								1/6/26
-173	3018	South Tank Fam	3000	OOS								1/6/26
-174	12001	Gasoline Tank Farm	12000	Heavy Naptha								1/7/26
-175	5013	Gasoline Tank Farm	5000					Y	Y	Y		1/7/26
ATC -176	3012		3000									

Comments: VGO = Virgin Gas Oil, lighter than diesel, can be refined to kerosene.K1 = VGO that has not been refined
ATC -176 will be replacing PTO 97.

MULTIPLE FIXED ROOF TANK INSPECTION FORM

Company Name: KERN ENERGY **Facility #:** S-37

Inspector Name: CRISTELA AVALOS **Hydrocarbon Analyzer Make/Number:** TVA 4, 5, 6, 9; FLIR Camera 1 & 2

Tanks Removed or relocated? ☐Y☒N
If Y, Demo release/ATC submitted ? ☐Y☐N ☒NA
(PTO must be cancelled if demo'd)
(Specify tanks in comments section)

Sump Present? ☐Y ☒N
If Y, Is the facility in compliance with 4402? ☐Y☐N

Voluntary I&M Participant? ☒Y ☐N
If Y, Required maint. & self-inspections performed? ☒Y ☐N
(Mark participating tanks with an * next to the PTO #)

PTO #	ID#	Location	Tank Capacity (BBL)	Contents	TVP/limit (psi)	TVP Test Date	THRPUT/limit	PVRV Present?	Subject to leak req.?	Under TVR?	Leak Value/ Location	Date
Exempt	5012	Near Flare Compressors	5000	Non-pota	ble water				N			
Exempt	5060	Waste Water Plant	5000	Water					N			
Exempt	5064	SE Water treatement facility	5000	Produced	Water				N			
Exempt	6300	Diesel Tank Farm	6000	Water					N			
Exempt	55001	Diesel Tank Farm	55000	TC1500	Sales				N			
Exempt	16003	Diesel Tank Farm	16000	Carb Diesel					N			
Exempt	16004	Diesel Tank Farm	16000	Carb Diesel B20					N			
Exempt	504	Middle Tank Farm	500	OOS					N			
Exempt	16001	South Tank Farm	16000	VGO					N			
Exempt	16002	South tank Farm	16000	Kerosene					N			
Exempt	3021	Tracks Tank Farm	3000	K1-Kerosene					N			
Exempt	3022	Tracks Tank Farm	3000	JC747					N			
Exempt	3023	Tracks Tank Farm	3000	EB-Geeb					N			
Exempt	10006	Tracks Tank Farm	10000	AGO					N			

Comments: * Tank 504 – Previously held Kerosene for Cogen-currently empty.

COMPONENT LDAR INSPECTION FORM
COGR / 4401 / 4409 / 4623 (Circle Only One)

Owner/Operator: Kern Energy

Site Name/ Lease(s): South, Gasoline, Middle Tank Farms

Inspector(s): C. Avalos & K. Born; S. Miller

Registration/PTO/ATC #: S-37-20-52-53-97-125-150-171-172-173, -44, -56, -12, -14, -19, -24, -25, -26, -22, -21, -23, -18, -13, -15, -50, -174, -16, -61, -175, -48, -49, -153, -90, -91, -57, -102, -154, -20, -53, -52, -97, -125

Analyzer(s) #: TVA4|061

Inspection Date(s): 1/6/26; 1/7/26

Equipment (ie. Wells/Tanks/SGs):
South tank Farm 1/6
3016, 3017, 3015, 3027, 3026
3014, 3015, 3018, 5007, 5009
5008
Gasoline Tank Farm 1/7
10007, 5010, 5020, 1100, 505,
5009, 501, 10008, 12001, 12000
5014, 5015, 16005, 2501, 2502,
5017, 10005, 16006
Middle Tank Farm
10000, 10001, 10002, 3012, 3013

Leak/Open Ended Line Location	Gas/Liq. Leak ppm/rate	Leak Type	Insp. Date	Repair Date	Re-insp. Date
Tank 12000 - Emergency hatch NOV ☐	091	Major ☐ Minor ☐	1/7/26	1/14/26	1/15/26
Tank 12000 - Emergency hatch & PVRV Vacuum side NOV ☐	091	Major ☐ Minor ☐	1/15/26	1/27/26	5/28/26
Tank 10002 - N & S hatch & PVRV NOV ☐	091	Major ☐ Minor ☐	1/6/26	1/13/26	1/15/26
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			

(Mark Critical and/or Essential components with an * next to Location)

Component Count: XXXXXXXXXX

Total Count: 50

*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

COMPONENT LDAR INSPECTION FORM
COGR / 4401 / 4409 / 4623 (Circle Only One)

Owner/Operator: Kern

Site Name/ Lease(s): TracusFarm ; Diesel tank

Inspector(s): C. Avalos , K. Born.

Registration/PTO/ATC #: S-37-111-148-126-59-51-95-9

Analyzer(s) #: TVA9 FLIR#1

Inspection Date(s): 5/6/26

Equipment (ie. Wells/Tanks/SGs):

Tracks 10003
55000 10004
54000
55002 Diesel Tank Farm
20000
20001

Leak/Open Ended Line Location	Gas/Liq. Leak ppm/rate	Leak Type	Insp. Date	Repair Date	Re-insp. Date
54000 - 2 socks 2 scals inaccessible NOV ☐		Major ☐ Minor ☐	5/6/26	5/12/26	6/3/26
NOV ☐		Major ☐ Minor ☐			
55002- 4 holes on N of flange west hole NOV ☐	11,200	Major ☒ Minor ☐	5/6/26	5/7/26	5/13/26
55002- 1 hole - N of flange east hole NOV ☐	12,900	Major ☒ Minor ☐	5/6/26	5/7/26	5/13/26
55002 1 hole - ~~3~~ 3ft E of flange NOV ☐	11800	Major ☒ Minor ☐	5/6/26	5/7/26	5/13/26
55002- inaccessible 2ft W of tank edge East tank NOV ☐		Major ☐ Minor ☐	5/6/26	5/8/26	5/27/26
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			

(Mark Critical and/or Essential components with an * next to Location)

Component Count: XXX

Total Count: 15

*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

COMPONENT LDAR INSPECTION FORM
COGR / 4401 / 4409 / 4623 (Circle Only One)

Owner/Operator: KERN ENERGY

Site Name/ Lease(s): CSA

Inspector(s): C. Avalos, R. Chavez

Registration/PTO/ATC #: S-37-28-34-130-131-27

Analyzer(s) #: TVA #7; FLIR 1

Inspection Date(s): 5/14/26

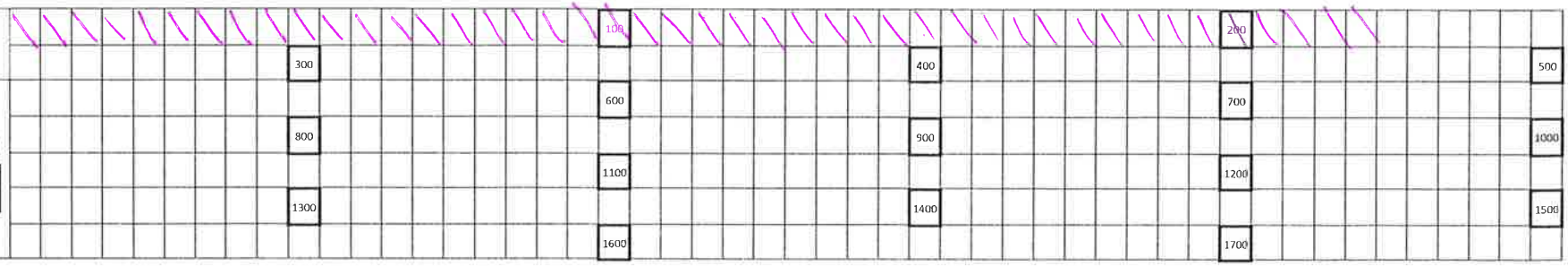
Equipment (ie. Wells/Tanks/SGs):
80000
80001
TVR
74000
74001
37000

Leak/Open Ended Line Location	Gas/Liq. Leak ppm/rate	Leak Type	Insp. Date	Repair Date	Re-insp. Date
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			
NOV ☐		Major ☐ Minor ☐			

(Mark Critical and/or Essential components with an * next to Location)

Component Count

Total Count: 220



*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

RECONCILING LEAKING COMPONENTS
RULE 4623

Owner/Operator: Kern Energy
Facility #: S-37
Location (Lease/Field): South, Gasoline, Middle, Tracks, Diesel, CSA Tank Farms
Analyzer(s) #: TVAs # 6, 9 and OGI camera
Inspector(s): C. Avalos, K. Born, S. Miller, R. Chavez
Date(s): 1/6/26, 1/7/26, 5/6/26, 5/14/26

Total Number of Leaks (500 to 10,000 ppmv)	÷	Total Number of Components Inspected (if ≤200 use number, if >200 use percent)	=	Leak Number/Percent	Compliance
0	÷	285	=	0%	Y:☒ N:☐ NOV:

Total Number of Major Gas Leaks (>10,000 ppmv)	Compliance	Total Number of Liquid Leaks	Compliance
3	Y:☐ N:☒ NOV: 5037853	0	Y:☒ N:☐ NOV:

Table 10 – Allowable Leaks

Leak Threshold	200 or Less Components Inspected*	More than 200 Components Inspected*
500 – 10,000 ppmv	5	2% of total inspected

* The maximum number of leaks in Table 10 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components inspected during the specified inspection period. Leaks counted toward the allowable leak threshold in Table 10 are still subject to the maintenance and repair requirements of Section 5.9.3 through 5.9.4.

Table 2 – Gas Leak

Non-specific	Minor Gas Leak	Major Gas Leak
Components	500 to 10,000 ppmv	Greater than 10,000 ppmv

Non-specific	Liquid Leak
Components	The dripping of organic liquid at a rate of more than 3 drops per minute

Table 11 – Repair Time Periods

Leak Threshold	Repair Time Period
Minor Leak	14 Calendar Days
Major Leak	2 Calendar Days
Liquid Leak	2 Calendar Days

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy ATC / PTO #: S-37-1-9-45

Location (Lease/Field):

Inspector (s): C. Avalos ; K. Born Date: 01/06/26

Analyzer Number: TVA-6

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
CRUDE UNIT							Rod	1
Middle Tank Farm							S. Piping	1
							PVRV	1
							Hatch	11
South Tank Farm							Sight glass	6
							Thermal capper	1
DEHY Treater							PR	1
Total Inspected:	219	352	270	4	2	15		13
Number of Leaks:	0	2	1	0	0	0		0

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy ATC / PTO #: S-37

Location:

Inspector(s): C. Avalos; K. Born Date: 1/6/26

Analyzer number: TVA #6

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	Valve	30120	Y	N		606ppm						1/6/26	1/16/26 @ 20ppm
2	TC	34975	Y	N		1016 ppm						1/8/26	1/15/26
3	Valve	30486	Y	N		3700ppm						1/16/26	1/17/26 15

@ ① under Born heater 1/6/26
② D-33 (Flange TC)
③ Light Naphta Level controller - 208

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37

Location (Lease/Field):

Inspector (s): C. Arros & S. Miller

Date: 1/7/26

Analyzer Number: TVA #4

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
Gasoline Tank Farm Blending manifold VRU - Plant					11		VENT	
							SS	
							Check Valve	
							Filter Bd	
							~~Regi~~ gauge	
							Control Valve	
							~~Dead lock~~	
							Cam Lock	
							Sight Glass	
							Nano Meter	
							Flame arrestor	
							Sight glass	
							Flex pipe	1
							Hose	
Total Inspected:	217	192	139		2	7		53
Number of Leaks:	0	3	1		0	1		0

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy ATC / PTO #: S-37

Location:

Inspector(s): C. Avalos; S. Miller Date: 1/7/26

Analyzer number: TVA #4

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) NOV	Major Liquid NOV	Open lines NOV	Repair Date	Re-insp. Date
1	Valve	30291	N	N	Liq	9900						1/8/26	1/15/26
2	Valve	15792	N	N	Liq	4,100						1/8/26	1/15/26
3	Plug	30035	N	N	Liq	7,165						1/7/26	1/7/26
4	Valve	107183	N	N	Liq	21577						1/9/26	1/15/26
5	Pump		N	N	Liq	587						1/8/26	1/15/26

(1) Blending manifold
(2) Blending manifold
(3) plant VRU
(4) Valve Tank 5017
(5) Pump 7126.65

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy ATC / PTO #: S-37-108-109-9

Location (Lease/Field):

Inspector (s): C. Arratos, S. Miller Date: 5/5/26

Analyzer Number:

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
LPG	51	35	20			6	Sight Glass	7
WWTP							VENT	
							Sump	
							Drain	
							SS tubing	
Total Inspected:	51	35	20			6		7
Number of Leaks:	0	0	0			0		0

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37-118 -164-119-165

Location (Lease/Field): NHT

Inspector (s): C. Avalos, K. Born

Date: 5/6/26

Analyzer Number: TVA #9

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
NHT Reformer				1	III		P. Reg	
							SS tubing	
							Sightglass	
							PSG	
							Drain	11
NHT Engine/Comp							filter pot	
Reformer Eng/Comp								
Diesel tank Farm								
Total Inspected:	251	271	218	1	3	10		17
Number of Leaks:	0	1	0	0	0	0		0

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy
Location:
Inspector(s): C Arcalos, K. Bom
Analyzer number: TVA 9

ATC / PTO #: S-37
Date: 5/6/26

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	Valve	18838		N		619ppm		X				5/4/26	5/6/26

5/6 ① at Reformer E of splitter

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37-77; -7

Location (Lease/Field): DHT

Inspector (s): C. AVALOS, K. BLOMBERG

Date: 5/13/26

Analyzer Number: TVA #5

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
DHT FLARE				11			1 (pot)	
							1 (prod pot)	11
							1 (sight glass)	
							1 (sight glass)	
							1 (sight glass)	1111
							1 (drain Pot) x	
							1 (waste bin?)	
							1 (drain)	
							1 Pod	
							SS tubing	
Total Inspected:	245	292	222	2	7	8		11
Number of Leaks:	0	2	0	0	0	0		1

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy ATC / PTO #: S-37-77-4-7

Location:

Inspector(s): C. Avalos; K. Blamberg

Analyzer number: TVA #5 Date: 5-13-2026

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) NOV	Major Liquid NOV	Open lines NOV	Repair Date	Re-insp. Date
	Valve	31966	N	N	Gas	6,700		X				5-13-26	5-13-26 ✓
	Drain	19855	N	N	~~Gas~~	750,000			X			5-13-26	5-13-26
	Valve	14859		N		73 drops/min		X liquid		~~X~~		5/15/20	5/20/26

(1) reboiler
(2) OVHD Receiver (liquid)
(3) West of D+IT compressor

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

COMPONENT INSPECTION FORM
RULE 4455

Company: KERN ENERGY

ATC / PTO #: S-37-38-149

Location (Lease/Field): CSA; Transmix; LRU

Inspector (s): C. AVALOS, R. CHAVEZ; S. Miller

Date: 5/14/26; 5/20/26

Analyzer Number: TVA #1

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
CSA	332	349	278			18	Hose	4
							Drain	5
							PVRV	1
							Hatch	1
							Lid (Sump)	1
Transmix							Pad/Filter	3
						1	Drain	5
							SG	7
							SS tubing	1
							Vent	1
							Connector	1
LRU								
Total Inspected:	332	349	278			18		31
Number of Leaks:	1	3	4			1		

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy

Location: Transmix; Transmix; LRU

Inspector(s):

Analyzer number: TVA #7

ATC / PTO #: S-37-38 & -149

Date: 5/14/26; 5/20/26

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) NOV	Major Liquid NOV	Open lines NOV	Repair Date	Re-insp. Date
①	Reflux Pump	32270				1449						5/19/26	5/20/26
②	flange	32270				910						5/19/26	5/20/26
③	T.C.	2+737				H000							
③	T.C	3506B				377						5/14/26	5/20/26
4	TC	318763			Liq	1100		X				5/20/26	5/20/26
5	Valve	09154			gas	1040 (2201)		X				5/26/26	5/27/26
6	TC	04988F6			Liq	292		X				5/26/26	5/27/26
7	drain					1300							
7	Valve	Vessel 5510-05			Liq	1330		X				5/26/26	5/27/26
8	Valve	09306			Liq	603 (2201)						5/21/26	5/27/26
9	TC	09262-1			Liq	385 (2201)		X				5/21/26	5/27/26

① Transmix Pump (P-7B) @ shaft Unit #1
② Transmix Unit #1 (P-7B) @ suction line to flange
③ ~~Transmix H2-RFG exit line flange to~~ Transmix Splitter #2 bottoms / Dsl Pump (P-11B)
↳ Bull plug on discharge

5/20/26
④ transmix
⑤ LRU
⑥ transmix - bottom tubing
⑦ transmix - under V4
⑧ LRU near V-11

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37-3 & -4

Location (Lease/Field): KHT; Platformer

Inspector (s): C Avalos C Carrillo

Date: 5/26/26

Analyzer Number: TVA 15

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
KHT Platformer	375	433	358	1	6	4	Drain sight glass SI tubing	17
Number of Leaks:	0	0	1	0	0	0		0

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy ATC / PTO #: S-37-3 & 4

Location:

Inspector(s): C. Avalos & C. Carillo Date: 5-26-26

Analyzer number: TVA #6

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) **NOV**	Major Liquid **NOV**	Open lines **NOV**	Repair Date	Re-insp. Date
1	FC	20604-1			Gas	1631 PPM		✓				5/26/26	5/26/26

(1) Burner # of heater 3535.13

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy ATC / PTO #: S-37

Location (Lease/Field):

Inspector (s): R. Chavez ; K. Born Date: 5/28/2026

Analyzer Number: TVA #5

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
SRU 2 & TGU 2						11	SG Lid	4 3
							Connector	1
							PVRV	1
Amine #2							Reg.	1
							Lid	11
Amine #1				111		1	Stain. Steel Con	19
							Sight Glass	1
							[illegible]	4
							Drain	1
							Lid	111
Total Inspected:	140	272	247	3		8		40
Number of Leaks:								

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

PAGE 1 OF 2

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy
Location (Lease/Field): Plat Splitter / Quad Reformer Comp
Inspector (s): R Chavez & K. Born
Analyzer Number: TVA 5

ATC / PTO #: S-37
Date: 5/28/2024

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
	243	399	408	3	2	10		15
Total Inspected:								
Number of Leaks:		3	1					

Splitter: 11 SG; 1 Drain; 11 PVRV; 1 Hatch
Quad Reform. Compressor: 1 PRD; 11 Drain; 1
Quad Plat. Comp.: 1 PRD; 11 SG; 11
N. Plat Recycle Comp: 1 PRD; 1
Lid: 1
Regulator: 1

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy — ATC / PTO #: S-37

Location: Amine #2 / Splitter

Inspector(s): R. Chavez & K. Born — Date: 5/28/2026

Analyzer number: _____

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) NOV	Major Liquid NOV	Open lines NOV	Repair Date	Re-insp. Date
①	Valve	28349			L	3drops/min		Liq		[redacted]		5/28/26	5/28/26
2	Valve	31806			G	750		750				5/28/26	5/28/26
3	Valve	31801			G	1586		1586				5/28/26	5/28/26
4	TC	33905			G	521						5/28/26	5/28/26

① 2" 150 Gate Valve, Amine Regen. Reflux Pump, outlet to drum, >3 drops/min (Amine #2)

② #2 Burner gas line to platform splitter reboiler; Repaired @ 10ppm

③ #3 2" gate valve packing; Repaired @ 0 ppm

④ N. Plat. Comp. needle valve cap; Repaired @ 0ppm

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

COMPONENT INSPECTION FORM
RULE 4455

Company: Kern Energy

ATC / PTO #: S-37-1221-120; 1211-4

Location (Lease/Field):

Inspector (s): S. Miller, C. Arialos

Date: 5/28/26

Analyzer Number: TVA #9

	Flanges	Valves	Threaded Connections	Pressure Relief Devices	Compressors	Pumps	Other Component Type	Other Component Count
SRU#1							Filter pod	11
SKid T&U							SS tubing	119
SRU skid							P. gauge	11
							Sight glass	
SW Stripper							Seperator	1
Vessels							Drain	
							Cooler	1
Amine #1								
Skid #2								
Platformer								
Total Inspected:	245	357	347	7	2	14		25
Number of Leaks:			1		1			

* "Other Component" includes, but is not limited to: Process Drains, Sight Glass, Pressure Gauge, Daniel Fitting, etc.

LEAKING COMPONENTS
RULE 4455

Company: Kern Energy

Location:

Inspector(s): S. Miller & C. Avalos

Analyzer number: TVA #9

ATC / PTO #: S-37-120;-121;-122;-4

Date: 5/28/26

Leak Number	Component Type	Component Tag Number	Repair Tag (Y/N)	Critical Essential (Y/N)	Service (Liq./Gas)	Concentration (ppm or %)	Major (>10K to 50K)	Minor (Liq./Gas)	Major (50K+) NOV	Major Liquid NOV	Open lines NOV	Repair Date	Re-insp. Date
①	TC	20091			Gas	750K			X			5/29/26	6/3/26
②	Comp	027953			Gas	1016						6/1/26	6/3/26

① SRU skid near SRU burner

② C-16 Compressor (Plat 6 Tanks)

Major Liquid Leak = visible mist or continuous flow
Minor Liquid leak = more than 3 drops / minute
Minor Gas Leak:

Component Type	Liquid Service	Gas/Vapor Service
Valves	200 to 10,000	400 to 10,000
Threaded Connections	200 to 10,000	400 to 10,000
Flanges	200 to 10,000	400 to 10,000
Pumps	500 to 10,000	500 to 10,000
Compressors	500 to 10,000	500 to 10,000
Pressure Relief Devices (PRD)	100 to 10,000	200 to 10,000
Other	500 to 10,000	1,000 to 10,000

Type of Leak	Repair Period in Calendary Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	7
Major Gas Leak Greater than 10,000ppm but equal to or less than 50,000ppm	3	2
Major Gas Leak greater than 50,000ppm	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

RECONCILING LEAKING COMPONENTS
RULE 4455

Number and percent of leaking components by component type (See Table 2 below):

Component Type	Total Number of leaks (Major + Minor)	÷	Total Number of Component Type Inspected (if <200 use number, if >200 use percent)	=	Leak Rate (%)	Status (OK or NOV)
Flanges	1	÷	2127	=	0.05%	OK
Valves	14	÷	2670	=	0.5%	OK
Threaded Connections	9	÷	2260	=	0.4%	OK
Compressor	1	÷	24	=	1 allowable leak	OK
Pumps	2	÷	78	=	2 allowable leaks	OK
Other	1	÷	25	=	1 allowable leak	OK
		÷		=		
		÷		=		
		÷		=		
		÷		=		
		÷		=		
		÷		=		

Table 2: Maximum allowable number or percent of leaking components per inspection period

Component Type	Maximum Number of Leaks for 200 or less Components Inspected	Maximum Percent or Number of Leaks for more than 200 Components Inspected
1. Valves	1	0.5% of number inspected
2. Threaded Connections	1	0.5% of number inspected
3. Flanges	1	0.5% of number inspected
4. Pumps	2	1.0% of number inspected
5. Compressors	1	1 leak
6. Pressure Relief Devices (PRD)	1	1 leak
7. Other component types not listed in items 1-6 above	1	1 leak
8. Pipes	2	2

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	1/6/26; 1/7/26	1/7/26	1/7/26	1/7/26	1/7/26	1/7/26
PTO Number:	-8-38	Exempt	-93-5	Exempt	-71-7	-43-2
Pump HP:					25	15
Product Type:	Gasoline; Diesel blending		PS1500		Transmix	Solvent
TVP:						
Leaks:	See comments	NA	None	NA	None	None
Number of Disconnects/Day:	NA		NA		NA	Zero
Daily Throughput:	NA		NA		w/i limits	NA
Daily Records Maintained:	SAT		SAT		NA	SAT
Leak Inspection Conducted:	NA		SAT		NA	SAT
Loading Rack ID:	A.F.K.L.N	B	C	D	E	G
Inspector:	CA	CA	CA	CA	CA	CA

Comments:

Rack L: 805ppm @ loading hose.

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.

** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.

*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	1/7/26	1/7/26	1/7/26	5/6/26	6/3/26	1/7/26
PTO Number:	-58-4	Exempt	Exempt	Exempt	Exempt	Exempt
Pump HP:	29					
Product Type:					Gasoline Additives	Pooling Station
TVP:						
Leaks:	None		OOS	NA	None	None
Number of Disconnects/Day:	NA					
Daily Throughput:	NA					
Daily Records Maintained:	SAT					
Leak Inspection Conducted:	SAT					
Loading Rack ID:	H	I	J	M	O	P
Inspector:	CA	CA	CA	CA	CA	CA

Comments:

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.

** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.

*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	6/3/26	5/6/26	5/6/26	6/3/26	5/5/26	5/6/26
PTO Number:	-46-7	-155	-147-2	-142-4	-107-5	-94-8
Pump HP:	30	30	30	<50		
Product Type:	Diesel, Ethanol; transmix; tolune	OOS	B100	Tallow	LPG, NG, Butane	Butane, JC747 blend component, B100, Ethanol, Alkylate
TVP:						
Leaks:	None	OOS	NA	NA	NA	See comments
Number of Disconnects/Day:	NA		2/20	NA	/Mo.	10/Mo
Daily Throughput:	w/i limits	OOS	NA	OOS	NA	NA
Daily Records Maintained:	SAT		SAT	YES	SAT	SAT
Leak Inspection Conducted:	SAT		NA	NA	NA	NA
Loading Rack ID:	Q	R	S	U	V	W
Inspector:	CA	CA	CA	CA	CA	CA

Comments:
Rack V – LPG Loading Racks: NOV #5037851
198ppm (2201 violation) @ Valve packing drylock seal.
8,670ppm @ TODO return hose.
11,000ppm @ Butane pump coupling.

Rack W – LPG Loading Racks: NOV #5037851
1,500ppm @ Valve packing.
2,000ppm @ plug threaded connection.
1,686ppm @ plug threaded connection at loading arm spot 3.

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.
** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.
*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

Rule 4624 – Transfer Rack Operation

Company: Kern Energy Facility ID: S-37

Date of Inspection:	5/6/26	5/9/26	5/14/26	1/7/26	6/3/26	6/3/26
PTO Number:	-138-4	-143-4	-139-4, 140-4,141-2	Exempt	Exempt	-67
Pump HP:	15	<50				
Product Type:	JC747, Kerosene, AGO	AGO	Crude Transmix			
TVP:						
Leaks:	None	None	See Comments	NA	OOS	OOS
Number of Disconnects/Day:	NA	NA	1/mo			
Daily Throughput:	965/23,016 gal	NA	NA			
Daily Records Maintained:	SAT	SAT	SAT		OOS	OOS
Leak Inspection Conducted:	NA	NA	NA			
Loading Rack ID:	X	Y	AA	BB	CC	T
Inspector:	CA	CA	CA	CA	CA	CA

Comments:

Rack AA - Lane 1:
1,981ppm @ West vapor hose connection. NOV #5037855

* Section 3.17.1 - For organic liquids other than gasoline, a concentration of VOC > 1,000 ppm above background shall constitute a leak.
** Section 3.17.2 - For gasoline, a concentration of VOC >10,000 ppm above background shall constitute a leak.
*** Switch loading shall only occur at racks with a permitted vapor collection and control system.

LEAKING COMPONENTS
RULE 4624

Owner/Operator: Kern Energy

Registration/PTO/ATC #: S-37-8; -71; -93; -58; -43; -46; -139; -142; -147; -107; -94; -143; -138

Site Name/ Lease(s): Racks A, E, C, F, H, G, K, L, M, N, Q, S, V, W, Y, X, AA

Analyzer(s) #: TVA 4, 7, 9

Inspector(s): C. Avalos; S. Miller; K. Born; R. Chavez

Inspection Date(s): 1/7/26; 5/5/26; 5/6/26; 5/14/26; 6/3/26

Equipment Type	Leak Location	Repair Tag #	Concentration (ppm or %)	Minor (500ppm to <1,000ppm)	Major (1,000 +) **NOV**	Inspection Date	Repair Date	Re-Insp. Date
Racks A, E, C, F, H, G, K, L, M, N, Q, S, V, W, Y, X, AA	Rack V: Valve packing	33748-2	198 ppm		X (2201)	5/5/26	5/6/26	5/6/26
	Rack V: Drylock seal	334715	8,670 ppm		X	5/5/26	5/6/26	5/6/26
	Rack V: Butane pump coupling	10711	11,000 ppm		X	5/5/26	5/8/26	5/13/26
	Rack W: Valve packing	29755	1,500 ppm		X	5/5/26	5/8/26	5/13/26
	Rack W: Plug-TC	34258	2,000 ppm		X	5/5/26	5/6/26	5/13/26
	Rack W-spot 11: Valve	08675	>3drops/min		X	5/6/26	5/7/26	5/13/26
	Rack W-spot 2: Hose	08450-2	1,686 ppm		X	5/6/26	5/8/26	5/13/26
	Rack W-Spot 3: Plug-TC	30385	956 ppm	X		5/6/26	5/6/26	5/6/26
	Rack L: loading hose	10142	805 ppm	X		5/6/26	5/8/26	5/13/26
	Rack AA-Ln 1: hose connection	28690	1,981 ppm		X	5/14/26	5/14/26	5/14/26
Total Number of Leaks:				2	7			

Component Count	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Total Count:	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
1160	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X																		

*Blank cell indicates a 0 count, marked cell indicates a count of 5, numbers less than a count of 5 will be indicated in the cell as 1-4.

Table 3 – Repair Time Periods	
Type of Leak	Repair Time Period
Liquid Leak	72 hours
Gas Leak	72 hours

Table 4 – Number of Allowable Leaks	
Minor Leaks	2% of Number Inspected
Major Leaks	7

Total Count	2% Allowable	NOV or OK
1160	23	OK

Stationary Gas Turbine Inspection Report
Rule 4703

Use this form in conjunction with the Compliance Inspection Summary

Inspection Type: ☒ Compliance ☐ Start-Up ☐ Re-Inspect ☐ Complaint ☐ Other

Company: Kern Energy ATC / PTO #: S-37-114

Contact: Gabe Castro Title: Environmental Mangr. Phone: _____

Location: Panama Lane and Weedpatch Hwy

Sec / Utm Sec: _____ Township / Utm West: _____ Range / Utm North: _____

All items are to be checked at the time of each Inspection.

EQUIPMENT:

Turbine Mfg: Solar-Tarus Model: 60-7901S S/N: _____

Maximum Heat Input: 5.5 ☒ Mw ☐ Btu/Hr Shaft H.P.? ☐Y / ☐N

Operating Cycle: ☐ Simple Cycle ☐ Combined Cycle Fuel Type: ☒ Gas ☐ Liquid

Control Equipment: ☒ SCR ☐ Nh3 Injection ☐ DLN Combustors ☐ Other _____

Emissions Category: ☐ Tier 1 ☐ Tier 2 ☐ Tier 3 ☐ Tier 4

Exempt From 4703? ☐ Laboratory Unit ☐ Firefight / Flood Control ☐ Emergency ☐ < 4mw & 877hr

Monitoring: ☐ CEMS ☒ Alternate Monitoring ☐ Op Characteristics

Gen Set Mfg: _____ Model: _____ S/N: _____

Max Output: _____ ☐ KW ☐ Kva ☐ 120 Vac ☐ 220 Vac ☐ 440 Vac

INSPECTION DATE:	11/13/24	1/6/26			
Conditions:					
OAT (°F):	64F	56F			
Wind Speed (mph):	3mph	4mph			
Wind Direction:	WNW	WNW			
Time In:	1:08 pm	12:25pm			
Time Out:					
Hour Meter Reading:					
Actual Hours Operated:	8,661	8,311			
Lube Oil Vent VEE:	☒Sat / ☐Ns	☒Sat / ☐Ns	☐Sat / ☐Ns	☐ Sat / ☐Ns	☐ Sat / ☐Ns
Turbine Inlet Temp:	566F	553F			
SCR Inlet Temp:	576F	557F			
NH_3 Inject Rate:	14.1lb/hr	20lb/hr			
Stack Temp:	299F	227F			

Inspection Date:	11/13/24	1/6/26			
Variance:					
On Schedule?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Compliance w/conditions?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Process Rates:					
Raw – Comply?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Finish – Comply?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Fuel – Comply?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Waste:					
Handling?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Storage?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Disposal?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Source Test:					
Date Last Test?	10/10/24	10/05/25			
Excess Emissions?	☐Y / ☒N	☐Y / ☒N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
CEMS:					
Proper Cal. Procedure?	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Reports?	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
ATC /PTO:					
On Site?	☒Y / ☐N	☒Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Accurate/Current?	☒Y / ☐N	☒Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Unpermitted Equipment?	☐Y / ☒N	☐Y / ☒N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Visible Emissions?	☒Sat / ☐Ns	☒Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Records?	☒Sat / ☐Ns	☒Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns	☐Sat / ☐Ns
Nuisance?	☐Y / ☒N	☐Y / ☒N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Violation Observed?	☐Y / ☒N	☒Y / ☐N	☐Y / ☐N	☐Y / ☐N	☐Y / ☐N
Issued:					
NOV#					
NTC#					
Inspector:	CA	CA			
Supervisor / Lead:					
Review Date:					

SOURCE: MULTI-ENGINE FORM (revised 10/27/09)

Location	Crude Unit	Water Plant		Crude Unit	Diesel Tanks					
PTO/ATC#: S-37	-80	-81	-82	-83	-123					
Engine Mfg:	Detroit	Cummins	Waukesha	Waukesha	Caterpillar					
Model:	12V71T	NT855F1	135GZU-15861	6 WAKB-10F	3408D1TA					
Horsepower / Tier	471	225	60	150	481	/	/	/	/	/
Family Name:										
S/N:	12VA075097			230263						
Applicable District Rule:	4702	4702	4702	4702	4702					
Engine Use:	Emergency	Emergency	Emergency	Emergency	Emergency					
Allowable hours:	20	100	100	100	100					
Engine powers:	Generator	Firewater	Firewater	Compressor	Firewater					
Fuel:	Diesel	Diesel	NG	NG	Diesel					
[1]Induction:	Turbo	Turbo	Naturally Asp	NaturallyAsp	Turbo					
[2]Exhaust:	Uncontrolled	Uncontrolled	Uncontrolled	Uncontrolled	Uncontrolled					
[3]Exhaust stack:	Flapper	Flapper	Flapper	Flapper	Flapper					
[4]Crankcase vent:	PCV	PCV								
Timing Certificate on File:										
[5] Rich Burn/Lean Burn				Rich						
Drinking Water System Engine?										
Is it De-Rated:										
[6]How is it de-rated:										
Inspection Date:	1/6/2026	6/3/2026		1/6/2026	6/3/2026					
[7]VEE: SO/VEE(pass or fail) or No	SB	OP	ABND	SB	SB					
Hour Meter Reading:	2195.9	967.5		116.9	356.4					
Last yrs Meter Reading:	2178	906.1		116.7	288.6					
[8]Hours Operated per Year	17.9	22.4		0.2	67.8					
Fuel Meter Reading:										
Catalyst Temp Inlet/Outlet:	/		/	/	/	/	/	/	/	/
Analyzer Results (CO):/limits										
Analyzer Results (NOx):/limits										
Analyzer Results (02):/limits										
Source Test Date:										
Req. Maint. Performed:										
Monthly Monitoring Records:	SAT	SAT	SAT	SAT	SAT					
Inspection Results:	SAT	SAT	SAT	SAT	SAT					.
Inspector Initials:	CA	CA	CA	CA	CA					

MULTIPLE FIRED EQUIPMENT FORM

Company Name:		Kern Energy				Facility ID:			S-37			
Contact & Phone:		Gabe Castro				Inspector Name:			C. Avalos, K. Born, S. Miller, R. Chavez, C. Carillo, K.			
Inspection Date:		1/6/26; 5/6/26; 5/20/26; 5/13/26; 5/26/26; 5/28/26				Portable Analyzer Make/ Number:			Testos 7, 8, 9			
PTO	**Equip #**	**Refining Unit**	**Rating (MM/BTU)**	**Burner Mfg.**	**Burner Model**	**Serial #**	**Fuel Type**	**Analyzer Results NOx-CO-O2**	**Permit Limits Nox/CO ppm**	**Stack °F**	**VEE/ SO**	**Other**
-1	Tulsa	Crude	60				RFG/NG	11.3-0-7%	9/150		SO	Testo #9 (1/6/26) Avrg. NOX 11.3 - OK
	Born	Crude	60				RFG/NG	20.6-0-5.3%	15/150		SO	Testo #9 (1/6/26)Averg NOX 20.6 - NOV
-3	Charge	Unifiner (KHT)	11.4	Zeeco	GLSF-10		RFG/NG	17-0-5%	25/50		SO	Testo #8 (5/20/26)
	Splitter Reboiler	"	12.5	Zeeco	GLSF-10		RFG/NG	8.6-0-5.6%	25/50		SO	Testo #8 (5/20/26)
-4	Charge#1	Platformer	29.3	Zeeco	GLSF-12		RFG/NG	16-0-7%	25/51		SO	Testo #8 (5/26/26)
	Charge#2	"	17.9	Zeeco	GLSF-12		RFG/NG	15.9-0-7%	25/52		SO	Testo #8 (5/26/26)
	Charge#3	"	11.9	Zeeco	GLSF-10		RFG/NG	17.4-0-7%	25/53		SO	Testo #8 (5/26/26)
-6	Coen	"										DEU
-38	Tube Heater (H-1)	Trasmix	3.75				RFG/NG	78.6-0-2%	30/400		SO	Testo #8 (5/14/26) Avrg NOx 78.6 - NOV
	Tube Heater (H-2)	"	3.67				RFG/NG	9-40-5.6%	9/250		SO	Testo #8 (5/14/26)
-77	Charge	DHT	18	Zeeco	GLSF-11		RFG	20.4-0-6.5%	25/50		SO	Testo 7 (5/13/26) Avrg NOx 20.4ppm
	Stripper Heater	DHT	18	Callidus	LE-CSG		RFG	23.8-0-3.6%	25/150		SO	Testo 7 (5/13/26) Avrg NOx 23.8 ppm
-116	Splitter Reboiler	Platformer Splitter	14.1				RFG/NG	21.5-15-7.5%	30/239		SO	Testo 8 (5/26/26)
-118	Charger	NHT	12.6	John Zink			RFG/NG	30.6-0-6%	25/150		SO	Testo 9 (5/6/26) Avrg NOx 30.6
	Reboiler	NHT	11.1				RFG/NG	25.9-0-7%	25/150		SO	Testo 9 (5/6/26)
-119	Charger#1	Reformer	25.7	John Zink			RFG/NG	24.4-0-5.4%	25/150		SO	Testo 9 (5/6/26) Avrg NOx 24.4ppm
	Charger#2	"	13.4	John Zink				3.7-32-3.4%	25/150		SO	Testo 9 (5/6/26)
	Charger#3	"	8.9	John Zink				3.7-32-3.4%	25/10		SO	#2 & #3 use the same port
	Splitter/Stabilizer	"	8.3	John Zink			RFG/NG	SB	9/150			SB
-122	Incinerator	SRU #1	2.5	John Zink			RFG/NG	SB	95/150			SB
-152	Incinerator	SRU#2	1.9	Zeeco	GB-8S		RFG/NG	28-0-3.84%	95/150		SO	Testo #8 (5/28/26)
-158	Boiler #12	Crude Unit	27.6	Cleaver Broo	700-800-250ST		NG	4.6-0-5.7%	5/25		SO	Testo #9 (1/6/26)

Comments:	

SOURCE: MULTI-ENGINE FORM (revised 10/27/09)

PTO/ATC#: S-37	157	159	160	161	163	164	165			
Engine Mfg:	Wauksha	Wauksha	Wauksha	Wauksha	Wauksha	Wauksha	Wauksha			
Model:	F18G	F18SE	F18SE	F18SE	F18SE	F18SE	F18SE			
Horsepower / Tier	240	310	310	310	310	310	310	/	/	/
Location	DHT Recyc	North Platf	South Platf	KHT West	KHT East	NHT Recy	Reforner Recycler			
S/N:	5283705292	5283705407	5283705396	5263705417	5283705763	5283705788	5283705788			
Applicable District Rule:	4702	4702	4702	4702	4702	4702	4702			
Engine Use:	Fulltime	Fulltime	Fulltime	Fulltime	Fulltime	Fulltime	Fulltime			
Allowable hours:	NA	NA	NA	NA	NA	NA	NA			
Engine powers:	Compressor	Compressor	Compressor	Compressor	Compressor	Compressor	Compressor			
Fuel:	NG	NG	NG	NG	NG	NG	NG			
[1]Induction:	Natural Spire	Natural Spire	Natural Spire	Natural Spire	Natural Spire	Natural Spire	Natural Spire			
[2]Exhaust:	Catalytic	Catalytic	Catalytic	Catalytic	Catalytic	Catalytic	Catalytic			
[3]Exhaust stack:	Open	Open	Flapper	Flapper	Open	Flapper	Flapper			
[4]Crankcase vent:										
Timing Certificate on File:										
[5] Rich Burn/Lean Burn	Rich	Rich	Rich	Rich	Rich	Rich	Rich			
Drinking Water System Engine?	No	No	No	No	No	No	No			
Is it De-Rated:	No	No	No	No	No	No	No			
[6]How is it de-rated:										
Inspection Date:	5/13/2026	5/27/2026	5/27/2026	5/20/2026	5/20/2026	5/6/2026	5/6/2026			
[7]VEE: SO/VEE(pass or fail) or No	SO	SB	SO	SB	SO	SO	SO			
Hour Meter Reading:	NA	NA	NA	NA	NA	NA	NA			
Last yrs Meter Reading:	NA	NA	NA	NA	NA	NA	NA			
[8]Hours Operated per Year (2025)	7,474	5,491	2,852.70	6,402	1,763	6,456	8,092			
Fuel Meter Reading:										
Catalyst Temp Inlet/Outlet:	/	/	/	/	/	/	/	/	/	
Analyzer Results (CO):/limits	15 / 56	/56	30 / 56	/ 56	47 / 56	82 / 56	358/56			
Analyzer Results (NOx):/limits	1.7 / 5	/5	2.3 / 5	/ 5	0 / 5	6.5 / 5	- / 5			
Analyzer Results (02):/limits	1 / 15%	/15%	0 /15%	/ 15%	/15%	0.2 /15%	0.2 / 15%			
Source Test Date:	2/12/2026	6/1/2026	1/15/2025	9/17/2026	2/26/2026	9/28/2025	8/28/2025			
Req. Maint. Performed:	SAT	SAT	SAT	SAT	SAT	SAT	SAT			
Monthly Monitoring Records:	SAT	SAT	SAT	SAT	SAT	SAT	SAT			
Inspection Results:	SAT	SAT	SAT	SAT	SAT	NOV	NOV		.	
Inspector Initials:	CA	CA	CA	CA	CA	CA/	CA			

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

☐ Northern Region Office
4800 Enterprise Way
Modesto, CA 95356-8718
(209) 557-6400

☐ Central Region Office
1990 E. Gettysburg Ave.
Fresno, CA 93726-0244
(559) 230-5950

☒ Southern Region Office
34946 Flyover Court
Bakersfield, CA 93308-9725
(661) 392-5500

Gasoline Vapor Recovery Inspection Form

Station Name: Kern Oil & Refining Co. PTO: S-37-127-4

Location: Panama Lane & Weedpatch Hwy City: Bakersfield Phone # : (661) 845-0761 office

Compliance Contact: Thomas Landeros Title: Environnmental Advisor

Inspection Type: ☒Compliance ☐ Complaint ☐ Start Up Start Up Date: _____ Test Date: _____

Follow-up to: _____ Notice of Violation # 5037858 Notice to Comply # _____

Phase I					
Executive Order: **VR-401-C**					
☐UST	☒AST	Tank Type: **Fireguard**			
		Standing Loss Control Compliant? **Yes**			
		Configuration: **Two-point**			
Tank Measurements					
Tank Size		9,000	3,000		
Product Type		87	Diesel		
Location		E	W		
Fill Config.		remote			
Tank Depth					
Fill Tube Length					
Diff (6" or less					

Phase II		
Executive Order: **G-70-52AM**	Type: **Balance**	Nozzles: 1
Phase II Control Type: **None**	PMC Version: N/A	
ISD		
ISD Installed? **No**	ISD Type:	ISD Version:
*if ISD is not installed facility is limited to 600,000 gallons/year		
ISD Currently in alarm?	Alarm History log on-site?	
Is facility responding to alarms?		
Maintenance		
Maintenance Required? **N/A**	Maintenance Performed?	
Date of last maintenance inspection:		
Self-Inspections		
Self-Inspection Records: **Yes**	Self-inspection frequency: **Monthly**	
Throughput: 165,102 gallons **annual**		

Inspection result: ☐ **No defects noted** ☒ **Defects noted (below):** Items corrected during inspection

Location	Product	Equipment	Defect	Result/Action required
Nozzle 2	87	upper hose	Gas-leak 13,000ppm	Tagged out of service until repaired

Comments: Facility replaced the hose on 6/3/26 and reinspected on the same date at 1:17pm. District reinspected for complaince on 7/2/26.

Inspector: Cristela Avalos Date: 06/03/26

When repairs are complete call: _____ Signature of Receipt: _____

NOTE: CA Health & Safety Code, Section 41960.2 (a) – Maintenance of Installed Systems. (e) Requires that the above listed 7-day deficiencies be repaired within 7 days. Failure to do so will result in legal action.

For important updates and information regarding gasoline dispensing operation requirements, please join our email notification list for Gasoline Vapor Recovery at: http://www.valleyair.org/lists/list.htm

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FLARE INSPECTION FORM

Company: **Kern Energy** **Permit #:** **S-37-7**

Contact: Gabe Castro Phone #: 661-845-0761

Location: 7724 E. Panama Lane Sec: _____ T: _____ R: _____

Equipment #: _____ Type of Unit: Flare

Make of Unit: JOHN ZINK STF-S-8 STEAM ASSIST FLARE Model: _____ Serial #: _____

BTU/HR Rating: Unknown Opacity Limit: Method 22; any 5 minutes during 2 consecutive hours

Fuel Type: ☐ H2S Gas ☐ Natural Gas ☒ Produced Gas ☐ N/A

Permitted Operating Schedule: 25,000 MMBtu/yr.

Inspection Date:	12/17/24	5/13/26	_____	_____	_____
VEE Conducted:	☒Sat ☐Ns ☐N/A	☒Sat ☐Ns ☐N/A	☐Sat ☐Ns ☐N/A	☐Sat ☐Ns ☐N/A	☐Sat ☐Ns ☐N/A
Determined by:	☐VEE/ ☒SO	☐VEE/ ☒SO	☐VEE/ ☐SO	☐VEE/ ☐SO	☐VEE/ ☐SO
Hrs Operated:	NA	NA	_____	_____	_____
MMscf/year:	5,578 MMBtu	5,769 MMBtu	_____	_____	_____
MMscf/day:	NA	NA	_____	_____	_____
H_2S ppm:	162 ppm (limit)	162 ppm (limit)	_____	_____	_____
Permits Posted:	☒Yes ☐No	☒Yes ☐No	☐Yes ☐No	☐Yes ☐No	☐Yes ☐No
Inspector:	CA	CA	_____	_____	_____

Comments:

Exhibit 11

Proposed Amendments to District Leak Detection And Repair Rules 4401, 4409, 4455, 4623 and 4624

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

GOVERNING BOARD

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Southern Region Office
34946 Flyover Court
Bakersfield, CA 93308-9725
(661) 392-5500 • FAX (661) 392-5585

www.valleyair.org

DATE: June 15, 2023

TO: SJVUAPCD Governing Board

FROM: Samir Sheikh, Executive Director/APCO
Project Coordinator: Sheraz Gill

RE: **ITEM NUMBER 12: ADOPT PROPOSED AMENDMENTS TO DISTRICT LEAK DETECTION AND REPAIR RULES 4401, 4409, 4455, 4623, AND 4624**

RECOMMENDATIONS:

1. Adopt proposed amendments to Rule 4401 (Steam-Enhanced Crude Oil Production Wells), Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities), Rule 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants), Rule 4623 (Storage of Organic Liquids), and Rule 4624 (Transfer of Organic Liquid).

2. Authorize the Chair to sign the attached Resolution.

BACKGROUND:

The San Joaquin Valley Air Pollution Control District (District) is committed to protecting public health for all residents in the San Joaquin Valley (Valley) through efforts to meet health-based state and federal ambient air quality standards with efficient, effective, and entrepreneurial air quality management strategies. In response to the latest federal mandates and to improve quality of life for Valley residents, the District has developed and implemented multiple generations of rules on various sources of air pollution. Valley businesses are currently subject to the most stringent air quality regulations in the nation. Since 1992, the District has adopted over 650 rules to implement an aggressive on-going control strategy to reduce emissions in the Valley, resulting in air quality benefits throughout the Valley. Similarly, the California Air Resources Board

(CARB) has adopted increasingly stringent regulations for mobile sources. Together, these efforts represent the nation's toughest suite of air pollution emissions controls and have greatly contributed to reduced ozone and particulate matter concentrations across the Valley.

Under Assembly Bill (AB) 617, nonattainment areas must adopt an expedited schedule to implement the most current Best Available Retrofit Control Technology (BARCT) limits on industrial sources that are subject to the state Cap-and-Trade program. Your Board approved an expedited BARCT implementation schedule in December 2018. As part of the BARCT Rule Evaluation, the District identified more stringent leak detection and repair (LDAR) leak thresholds, repair times, and frequency of inspection in other district, state, and federal regulations. Therefore, the District conducted a broader rule making effort, including a comprehensive technical analysis, in-depth review of local, state, and federal regulations, cost-effectiveness analysis, and a robust public process, and developed proposed rule amendments for your Board's consideration to address BARCT requirements.

On September 30, 2022, the U.S. Environmental Protection Agency (EPA) finalized in the Federal Register a limited approval, limited disapproval of CARB's Oil and Natural Gas Regulation (COGR). The Technical Support Document (TSD) from this action references EPA's 2016 Control Techniques Guidelines (CTG) for Oil and Natural Gas Facilities as containing EPA's Reasonably Available Control Technology (RACT) recommendations for reducing volatile organic compound (VOC) emissions from special equipment and processes used in the oil and natural gas industry. In addition to the deficiencies outlined in COGR, EPA's TSD also outlined deficiencies in multiple air districts' rules, including District Rules 4401, and 4623, which the District is fully addressing in this proposal.

In addition, your Board recently adopted the *2022 Plan for the 2015 8-Hour Ozone Standard* (*2022 Ozone Plan*) in December 2022. Building on decades of developing and implementing effective air pollution control strategies, this Plan demonstrates that the reductions being achieved by the District and CARB strategy ensures expeditious attainment of the 2015 8-hour ozone standard by the 2037 attainment deadline. Among this attainment strategy is a commitment to evaluate potential enhancements to the District's LDAR requirements for the oil and natural gas sector.

The proposed amendments to District Rules 4401, 4409, 4455, 4623, and 4624 include establishing more stringent LDAR requirements for VOC emissions from various types of components. Additionally, in order to provide better service to stakeholders and affected industry, the proposed rule amendments simplify and clarify existing rule standards and language. The proposed amendments address BARCT and RACT requirements as required under the Federal Clean Air Act (CAA) and California CAA, and were developed in close coordination with CARB and U.S. EPA. The proposed regulatory amendments also satisfy the District's commitment in the District's *2022 Ozone Plan*, to support expeditious attainment of the health-based federal ozone air quality standards.

The proposed amendments were developed through a public engagement process that solicited feedback from the public through a variety of forums, including workshops, meetings with affected sources and other interested parties. The purpose of this item is to seek your Board's approval of the proposed amendments to District Rules 4401, 4409, 4455, 4623, and 4624.

DISCUSSION:

Over the years, the District has adopted numerous generations of rules and rule amendments to reduce emissions from oil and gas production operations, petroleum refineries, natural gas processing plants, and organic liquid storage and transfer operations. These operations contain components, including valves, fittings, threaded connections, pumps, compressors, pressure relief devices, pipes, polished rods, stuffing boxes, flanges, process drains, sealing mechanisms, hatches, sight glasses, meters, and other components. These components are necessary to contain, monitor, and control the transfer of fluids (oil, gas, and petroleum products). However, leaking components emit VOC, methane, and other emissions. To reduce fugitive VOC emissions as ozone precursors, the District, CARB, and U.S. EPA have adopted regulations with LDAR programs applicable to these operations, which require the identification of components, leak thresholds, monitoring, repair timeframes, and recordkeeping. These regulations are enforced through permitting and enforcement programs in coordination with state and federal agencies. The implementation of these rules has significantly reduced VOC emissions from these source categories.

Summary of District Regulations

Rule 4401 was adopted in April 1991, and has been amended several times with the most recent amendments occurring in June 2011. Rule 4401 applies to all steam-enhanced crude oil production wells and any associated VOC collection and control systems. The purpose of this Rule is to limit VOC emissions from these sources, particularly from well casing vents. VOC emissions can also occur from components serving both open and closed casing systems.

Rule 4409 was adopted in April 2005. Rule 4409 applies to components containing or contacting VOC streams at light crude oil production facilities, natural gas production facilities, and natural gas processing facilities. The purpose of this Rule is to limit VOC emissions from components at these facilities, including, but not limited to, valves, fittings, threaded connections, pumps, compressors, pressure relief devices, pipes, polished rod stuffing boxes, flanges, process drains, sealing mechanisms, hatches, sight-glasses, meters, or seal fluid systems in VOC service.

Rule 4455 was adopted in April 2005. Rule 4455 applies to components containing or contacting VOC streams at petroleum refineries, gas liquid processing facilities, and chemical facilities. The purpose of this Rule is to limit VOC emissions from components

at these facilities, including, but not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, flange, process drain, sealing mechanism, hatch, sight-glass, meter or seal fluid system in VOC service.

Rule 4623 was adopted in April 1991, and has been amended several times with the most recent amendments occurring in May 2005. Rule 4623 applies to tanks that store organic liquids and have a capacity of at least 1,100 gallons. The purpose of the rule is to limit VOC emissions by requiring proper maintenance of tanks, use of pressure-vacuum relief valves and/or vapor control systems for various tanks.

Rule 4624 was adopted in April 1991, and has been amended several times with the most recent amendments occurring in December 2007. Rule 4624 applies to organic liquid transfer facilities. The purpose of this Rule is to limit VOC emissions associated with the transfer of organic liquids from both loading and unloading racks with stationary organic liquid pumps.

Pursuant to BARCT and RACT requirements, SIP-strengthening commitments in the *2022 Ozone Plan*, and consistent with the District's ongoing emission reduction efforts, the District is proposing amendments to District Rules 4401, 4409, 4455, 4623, and 4624 to further reduce emissions from these source categories. Table 1 illustrates the estimated SIP creditable emissions reductions achieved by the proposed rule amendments.

Table 1 - Estimated VOC Emission Reductions in Tons/Day

District Rules	Percent of Emissions Reduced	Tons/day of VOC Reduced
4401 and 4409	19.9%	0.20
4455	12.8%	0.02
4623	28.7%	0.69
4624	15.6%	0.18
	Total	**1.09**

Summary of Proposed Amendments

Based on the District's comprehensive analysis, including an in-depth review of local, state, and federal regulations, the District is proposing lower leak thresholds within the rules, quarterly inspections of all components, and shortened repair periods for certain types of leaks. The proposed amendments would provide consistency between the District's LDAR rules. The proposed emission limits and inspection frequencies for each rule are summarized in Table 2 below.

Table 2 - Proposed Rule Requirements

Rule 4401	Rule 4409	Rule 4455	Rule 4623	Rule 4624
Gas Leak • Minor: 500 to 10,000 ppmv • Major: >10,000 ppmv **LDAR Inspection** • Quarterly	**Gas Leak** • Minor: 500 to 10,000 ppmv • Major: >10,000 ppmv **LDAR Inspection** • Quarterly	**Gas Leak** • Minor: 500 to 10,000 ppmv • Major: >10,000 ppmv **LDAR Inspection** • Quarterly	**Gas Leak** • Minor: 500 to 10,000 ppmv • Major: >10,000 ppmv **LDAR Inspection** • Quarterly	**Gas Leak** • Minor: 500 to <1,000 ppmv • Major: 1,000 ppmv **LDAR Inspection** • Quarterly

The District is also modifying the applicability of Rule 4623 to require vapor control systems for crude oil storage tanks that have the potential to emit six tons of VOC or greater per year to provide consistency with the EPA CTG requirements. The minimum True Vapor Pressure (TVP) at which tanks are subject to Rule 4623 is also being changed from 0.5 psia to 0.1 psia. Furthermore, the amendments would subject one-half inch nominal or less stainless steel tube fittings to the requirements of Rules 4401, 4409, and 4455.

Other proposed amendments would also add language to clarify and provide consistency for definitions, remove expired language, and establish compliance timelines. The timeframes established in the proposed rules for facilities to meet the proposed leak limits and LDAR requirements reflect the time necessary for facilities to plan for full compliance, including budgeting for any required modifications to the facility or facility operations, modifying existing controls or facility control practices, and installing any required further control technologies. The proposed LDAR compliance deadline for all rules would be July 1, 2024. Tanks required to install vapor control systems or a pressure-vacuum relief valve will have until March 31, 2024, to submit an Authority to Construct (ATC) permit and have 12 months of the ATC issuance to comply with the requirements. The proposed amendments meet or exceed requirements for RACT, BARCT, and fulfill commitments within the *2022 Ozone Plan*.

Ongoing Coordination with Local, State, and Federal Agencies

The District will continue to evaluate opportunities to further reduce emissions from this source category, in close coordination with CARB, EPA, and local air districts. In particular, the District will evaluate ongoing evaluations and regulatory actions being conducted on the state and federal level, including continued efforts from EPA to strengthen their New Source Performance Standards and Emissions Guidelines for the oil and gas industry, and efforts from CARB to further amend their state regulation for oil and gas. The District will continue to collaborate with CARB and EPA through their evaluation processes, and assess any needed amendments to the District's rules to be consistent with state and federal requirements and guidance. In addition, the District will continue to track ongoing regulatory efforts being conducted at other local air districts.

Health Benefits of Proposed Amendments

The proposed amendments reduce fugitive VOC emissions from applicable sources, a contributor in the formation of ozone, from oil and natural gas sources as well as petroleum refining. Additionally, fugitive emissions may also contain hazardous air pollutants, such as benzene and other carcinogens known to cause adverse health impacts. Exposure to ozone has been linked to a variety of health issues, including chest pain, coughing, throat irritation, congestion, reduced lung function, and inflammation of the lining of the lungs. Repeated exposure to elevated concentrations of ozone may also permanently scar lung tissue. People with asthma, children, older adults, people active outdoors, and outdoor workers are at higher risk from exposure to high levels of ozone, and studies have linked rising hospital admissions and emergency room visits to higher ozone levels. The District has worked with CARB and EPA to reduce ground level ozone concentrations through the implementation of comprehensive emission reduction regulations while also incentivizing the implementation of low emission mobile source technologies through a variety of grant programs. Further reducing NOx and VOC emissions, the primary precursors to ozone formation, contributes to additional and significant public health and economic benefits in the San Joaquin Valley.

Supporting Regulatory Analyses

Cost Effectiveness Analysis
CH&SC Section 40920.6(a) requires the District to conduct both an absolute cost effectiveness analysis and an incremental cost effectiveness analysis of available emission control options before adopting each BARCT rule. The purpose of conducting a cost effectiveness analysis is to evaluate the economic reasonableness of the pollution control measure or rule. The analysis also serves as a guideline in developing the control requirements of a rule. Cost effectiveness will depend on the current level of controls, number of subject components, leak limits and final emission levels. Details of the cost effectiveness analysis is contained in Appendix C of the staff report.

Socioeconomic Impact Analysis
Pursuant to CH&SC Section 40728.5, “whenever a district intends to propose the adoption, amendment, or repeal of a rule or regulation that will significantly affect air quality or emissions limitations, that agency shall, to the extent data are available; perform an assessment of the socioeconomic impacts of the adoption, amendment, or repeal of the rule or regulation.” The final socioeconomic report is attached to the staff report as Appendix D.

Rule Consistency Analysis
Pursuant to CH&SC Section 40727.2, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of the rule or regulation with corresponding elements of existing or proposed District and EPA rules, regulations, and guidelines that apply to the same source category. District staff has concluded that the proposed rules are not in

conflict with nor inconsistent with other District rules, nor are the proposed rules in conflict with nor inconsistent with federal policy, rule, or regulations governing the same source category. The analysis is discussed further in Appendix E of the staff report.

Environmental Impacts
Based on the District's review, the rule amendments will not have the potential to cause any significant effects on the environment and as such is exempt from CEQA according to Section 15061 (b)(3) of the CEQA Guidelines. Furthermore, the rule amendments is an action taken by a regulatory agency, the San Joaquin Valley Air Pollution Control District, as authorized by state law to assure the maintenance, restoration, enhancement, or protection of air quality and is exempt by CEQA Guidelines §15308.

Rule Development Public Process

As part of the rule development process, the District conducted public workshops to present and discuss potential amendments to the District's LDAR Rules. The District shared information about public meetings with members of the public, source operators, consultants, vendors and manufacturers of control technologies, trade associations, and AB 617 community steering committee members. The District conducted public meetings/workshops in July 2020, December 2020, April 2021, October 2021, March 2022, October 2022, and April 2023. The District provided updates throughout the rule development process and BARCT evaluation to stakeholders.

At the rule development public workshops, the District presented the objectives of the proposed rulemaking project. The District published draft rules for public review on March 10, 2022, and April 17, 2023, to provide opportunity for public comment on draft amendments. Throughout the rule development process, District staff solicited information from affected source operators, consultants, and trade associations on the feasibility and compliance costs to assist the District in developing amendments to the LDAR Rules. The District incorporated comments received into the rule amendments as appropriate.

The proposed rule amendments were published for 30-day public review and comment on May 16, 2023, prior to the public hearing to consider the adoption of the proposed amendments by the District Governing Board.

The comments and questions received during the public engagement process have been integral to the development of the District's proposed amendments. Overall, the District has received public feedback seeking clarification of the proposed enhancements, in addition to suggestions regarding the stringency of the proposed leak limits and other proposed requirements. The District has incorporated suggestions as appropriate in the proposed rules. A summary of significant comments and District responses is available in Appendix A of the final draft staff report.

FISCAL IMPACT:

The District's 2022-23 Adopted Budget and 2023-24 Recommended Budget include sufficient resources to support the proposed regulatory amendments. The District will continue to evaluate resources needed to implement the proposed amendments, and incorporate those resources as necessary in future budget approvals.

Attachments:

Attachment A: Resolution for Proposed Amendments to District Leak Detection and Repair Rules (5 pages)
Attachment B: Proposed Amendments to Rules 4401, 4409, 4455, 4623, and 4624 (130 pages)
Attachment C: Final Draft Staff Report for Proposed Amendments to Rules 4401, 4409, 4455, 4623, and 4624 (190 pages)

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
June 15, 2023

ADOPT PROPOSED AMENDMENTS TO DISTRICT LEAK DETECTION AND REPAIR RULES 4401, 4409, 4455, 4623, AND 4624

Attachment A:

Resolution for Proposed Amendments to District Leak Detection and Repair Rules 4401, 4409, 4455, 4623, and 4624

(5 PAGES)

BEFORE THE GOVERNING BOARD OF THE
SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

IN THE MATTER OF: PROPOSED AMENDMENTS TO DISTRICT LEAK DETECTION AND REPAIR RULES 4401, 4409, 4455, 4623, AND 4624

) RESOLUTION NO. 2023-6-12
)
)

WHEREAS, the San Joaquin Valley Unified Air Pollution Control District (District) is a duly constituted unified air pollution control district, as provided in California Health and Safety Code (CH&SC) Sections (§) 40150 et seq. and 40600 et seq.; and

WHEREAS, said District is authorized by CH&SC §40702 to make and enforce all necessary and proper orders, rules, and regulations to accomplish the purpose of Division 26 of the CH&SC; and

WHEREAS, pursuant to federal Clean Air Act (CAA) §107, the San Joaquin Valley Air Basin (Valley) is designated as nonattainment for the national health-based air quality standards for ozone and particulate matter 2.5 microns and smaller (PM2.5); and

WHEREAS, the District Governing Board adopted the *2022 Plan for the 2015 8-Hour Ozone Standard* (*2022 Ozone Plan*) on December 15, 2022 pursuant to the federal Clean Air Act; and

WHEREAS, the District's *2022 Ozone Plan* commits the District to amend District Rule 4401 (Steam-Enhanced Crude Oil Production Wells), District Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities), District Rule 4455 (Components at Petroleum Refineries, Gas Liquid Processing Facilities, and Chemical Plants), District Rule 4623 (Storage Of Organic Liquids), and District Rule 4624 (Transfer of Organic Liquid) to further reduce VOC emissions from this source category; and

WHEREAS, Sections 182(b)(2) and 182(f) of the federal Clean Air Act (CAA) require areas that are classified as moderate or above for ozone nonattainment to implement Reasonably Available Control Technology (RACT) for sources subject to U.S. Environmental Protection Agency (EPA) Control Techniques Guidelines (CTG) or for

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"major sources" of NOx and volatile organic compounds (VOC); and

WHEREAS, on September 30, 2022, the EPA took final action in the *Federal Register* to provide limited approval and limited disapproval of California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, and cited specific issues to be addressed in District Rules 4401 and 4623 to satisfy federal RACT requirements as outlined in EPA's 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry (87 FR 59314-59320); and

WHEREAS, pursuant to California Assembly Bill 617 (AB 617), Rules 4401, 4409, 4455, 4623, and 4624 are required to meet Best Available Retrofit Control Technology (BARCT) requirements; and

WHEREAS, the District has coordinated with the California Air Resources Board (CARB) and United States Environmental Protection Agency (U.S. EPA) in developing the proposed amendments with respect to BARCT, RACT, and related state and federal regulations and guidance; and

WHEREAS, the staff report and other supporting documentation was presented to the District Governing Board and the Board has reviewed and considered the entirety of this information prior to approving the project; and

WHEREAS, District staff conducted public workshops regarding the proposed Rules on December 11, 2020, October 7, 2021, March 10, 2022, and April 17, 2023; and

WHEREAS, a public hearing for the adoption of proposed amendments to Rules 4401, 4409, 4455, 4623, and 4624 was duly noticed for June 15, 2023 in accordance with CH&SC §40725.

NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:

1. The Governing Board hereby adopts the proposed amendments to Rules 4401, 4409, 4455, 4623, and 4624. Said rules shall become effective on June 15, 2023.

2. The Governing Board hereby finds, based on the evidence and information presented at the hearing upon which its decision is based, that all notices required to be

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given by law have been duly given in accordance with CH&SC §40725, and the Governing Board has allowed public testimony in accordance with CH&SC §40726.

3. In connection with said rulemaking, the Governing Board makes the following findings as required by CH&SC §40727:

a. **NECESSITY.** The Governing Board finds, based on the staff report, public testimony, and the record for this rulemaking proceeding, that a need exists for said rule amendments. Amending Rules 4401, 4409, 4455, 4623, and 4624 is necessary to meet the commitments of the SIP and requirements of BARCT and RACT pursuant to the federal CAA and the California CAA. Said Rule amendments satisfy BARCT and RACT requirements, and the commitment in the District's *2022 Ozone Plan*.

b. **AUTHORITY.** The Governing Board finds that it has the legal authority for said rulemaking under CH&SC §40000 and 40001.

c. **CLARITY.** The Governing Board finds that the Rule amendments are written or displayed so that the meaning can be easily understood by those persons or industries directly affected by the Rules.

d. **CONSISTENCY.** The Governing Board finds that the Rules are in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

e. **NONDUPLICATION.** The Governing Board finds that the Rules do not impose the same requirements as any existing state or federal regulation.

f. **REFERENCE.** The Governing Board finds that said rulemaking implements federal CAA §172(c)(1) and CH&SC §40920.

4. The Governing Board hereby finds that the requirements of CH&SC §40728.5 and §40920.6 have been satisfied to the greatest extent possible, and that the Governing Board has actively considered and made a good faith effort to minimize any adverse socioeconomic impacts associated with the proposed rulemaking.

5. The Governing Board finds that this rulemaking is exempt from the California Environmental Quality Act (CEQA) per the general rule that CEQA applies only to

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projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061 (b)(3)). Furthermore, the proposed actions are exempt for actions taken by regulatory agencies, as authorized by state or local ordinance, to assure the maintenance, restoration, enhancement, or protection of the environment where the regulatory process involves procedures for protection of the environment (CEQA Guidelines §15308) (Actions by Regulatory Agencies for Protection of the Environment).

6. Pursuant to Section 15062 of the CEQA guidelines, the Executive Director/Air Pollution Control Officer is directed to file a Notice of Exemption with the County Clerks of each of the counties in the District.

7. The Executive Director/Air Pollution Control Officer is directed to file with all appropriate agencies certified copies of this resolution and the rules adopted herein and is directed to maintain a record of this rulemaking proceeding in accordance with CH&SC §40728.

8. The Executive Director/Air Pollution Control Officer is directed to transmit said rules to the California Air Resources Board for incorporation into the SIP.

9. The Governing Board authorizes the Executive Director/Air Pollution Control Officer to include in the submittal or subsequent documentation any technical corrections, clarifications, or additions that may be needed to secure EPA approval, provided such changes do not alter the substantive requirements of the approved rules.

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THE FOREGOING was passed and adopted by the following vote of the Governing Board of the San Joaquin Valley Unified Air Pollution Control District this 15th day of June 15, 2023, to wit:

AYES:

NOES:

ABSENT:

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

By _____
Vito Chiesa, Chair
Governing Board

ATTEST:
Deputy Clerk of the Governing Board

By _____
Katrina Rojas

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San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
June 15, 2023

ADOPT PROPOSED AMENDMENTS TO DISTRICT LEAK DETECTION AND REPAIR RULES 4401, 4409, 4455, 4623, AND 4624

Attachment B:

Proposed Amendments to Rules 4401, 4409, 4455, 4623, and 4624

(130 PAGES)

RULE 4401 STEAM-ENHANCED CRUDE OIL PRODUCTION WELLS (Adopted April 11, 1991; Amended September 19, 1991; Amended December 17, 1992; Amended January 15, 1998; Amended December 14, 2006, Amended June 16, 2011; Amended [*rule adoption date*])

1.0 Purpose

The purpose of this rule is to limit the Volatile Organic Compound (VOC) emissions from steam-enhanced crude oil production wells.

2.0 Applicability

This rule is applicable to all steam-enhanced crude oil production wells and any associated VOC collection and control systems.

3.0 Definitions

3.1 Air Pollution Control Officer (APCO): as defined in Rule 1020 (Definitions).

3.2 Background: a reading on a portable hydrocarbon detection instrument which is determined at a distance no greater than two (2) meters upwind from any component to be inspected and which is not influenced by any specific emission point.

3.3 Component: includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, flange, process drain, sealing mechanism, hatch, sight-glass, meter, or seal fluid system in VOC service.

3.4 Component Type: includes, but is not limited to, any one (1) of the following groups: valves, fittings, threaded connections, pumps, compressors, pressure relief devices, pipes, flanges, process drains, sealing mechanisms, hatches, sight-glasses, meters, or seal fluid systems in VOC service.

3.5 Compressor: a device used to compress gases or vapors or a combination of gases and vapors by the addition of energy, and includes all associated components used for connecting and sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) connected on the body of the compressor. For example, a valve that is connected to a threaded hole on the body of the compressor, the first VOC leak point is the threaded connection on the body side of the compressor, but the valve itself is not a "first VOC leak point". Similarly, a compressor shaft seal is considered as a “first VOC leak point”.

3.6 Critical Component: a component that would require the shutdown of a critical process unit if that component was shut down or disabled.

3.7 Critical Process Unit: a process unit that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

3.8 Critical Process Unit Shutdown: the shutdown of a critical process unit or part of the critical process unit that causes the entire unit to cease operating.

3.9 Cyclic Well: for purposes of this rule, a crude oil production well, which is periodically (at least once in the preceding two (2) year period) injected with steam from any source for the purpose of enhancing oil production.

3.10 District: San Joaquin Valley Unified Air Pollution Control District, or any person designated to act on its behalf.

3.11 EPA: United States Environmental Protection Agency, or any person designated to act on its behalf.

3.12 Essential Component: a component that cannot be taken out of service without reducing, by more than 33 percent, the throughput of the process unit that it serves.

3.13 Facility: a stationary source as defined in Rule 2201 (New and Modified Stationary Source Rule).

3.14 Fitting: a component, excluding flanges and threaded connectors, used to attach or connect pipes or piping system. Examples of a "fitting" include, but are not limited to quick-disconnect fittings, push-in-fittings, and cam-locks.

3.15 Front Line Production Equipment: a tank or vessel in which any organic liquid is placed, held, or stored and that is the first vessel that receives crude oil/fluids directly from wells subject to this rule including, but is not limited to, wash tanks, free water knockouts, separators, etc., and that is operating under atmospheric or near atmospheric pressure. After production is routed through at least one of such tanks or vessels, downstream vessels are no longer considered front line production equipment. A gauge tank, as defined in Section 3.0 of this rule, shall not be considered as Front Line Production Equipment.

3.16 Fuel Burning Equipment: as defined in Rule 1020 (Definitions).

3.17 Gauge Tank: for the purposes of this rule only, a tank which is used exclusively for measuring the amount of produced fluid produced by an oil well(s) and meets all the following conditions:

3.17.1 Has a capacity of 100 barrels (4,200 gallons) or less,

3.17.2 Is in operation on or before December 14, 2006,

3.17.3 Receives or stores produced fluid (crude oil or mixture of crude oil and water),

3.17.4 Is connected to at least one steam-enhanced crude oil production well with a closed vent,

3.17.5 Is upstream of all front line production equipment,

3.17.6 Does not have its VOC emissions controlled to at least 99%, and

3.17.7 The true vapor pressure (TVP) of the produced fluid in the gauge tank, at all times, shall be less than 0.5 psia as determined pursuant to the provisions of Section 6.2.3.

3.18 Inaccessible Component: a component that is located more than 15 feet above ground when access is required from the ground; or a component that is located more than six (6) feet away from a platform when access is required from the platform, or a component in a location that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.

3.19 Inspection: checking and/or testing in order to detect leaks.

3.19.1 District Inspection: inspection of components by District personnel or their representative to insure facilities and/or operators are in compliance with District requirements.

3.19.2 Operator Inspection: inspection of components conducted by the operator pursuant to the inspection and re-inspection schedules specified in this rule for the purpose of demonstrating compliance with this rule.

3.20 Leak: The dripping of VOC-containing liquid or the detection of a concentration of total organic compound, above background, determined according to the test method specified in Section 6.3.3 that exceeds any of the values specified in Table 1 <u>or Table 2,</u> Section 3.20.1 and Section 3.20.2 of this rule. Any liquid or gas coming from a component undergoing repair or replacement, or during sampling of process fluid from a component into a container is not considered a leak provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

Table 1 – Gas Leak in ppmv as Methane <u>until June 30, 2024</u>		
Type of Component	Major Gas Leak	Minor Gas Leak
1. PRDs	Greater than 10,000	400 to 10,000
2. Components other than PRDs	Greater than 10,000	2,000 to 10,000

Table 2 – Gas Leak in ppmv as Methane after June 30, 2024		
Type of Component	Major Gas Leak	Minor Gas Leak
1. PRDs	Greater than 10,000 to 50,000	400 to 10,000
2. Components other than PRDs	Greater than 10,000 to 50,000	500 to 10,000

3.20.1 Major Liquid Leak: a visible mist or a continuous flow of liquid that is not seal lubricant.

3.20.2 Minor Liquid Leak: a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute.

3.21 Leak Minimization: reducing a leak to the lowest achievable level without damaging the component using best modern practices which include, but are not limited to, adding sealing material to the component, tightening the component, or adjusting the component without shutdown of the process that the component serves and that can be safely accommodated.

3.22 Major Component: a pump five (5) brake horsepower or larger, any compressor, or any pressure relief ~~valve~~ device four (4) inches in diameter or larger.

3.23 Open-ended Line or Valve: a line or valve, except for pressure relief devices ~~PRV~~ and process drains, having one side of the line or valve seat in contact with the process fluid and one side open to the atmosphere, either directly or through an open piping.

3.24 Operate: to perform any activity with, or on any steam-enhanced crude oil production well, including but not limited to producing, steam-enhancing, venting, maintaining or repairing.

3.25 Optical Gas Imaging (OGI): an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

3.2~~5~~6 Pilot Testing: testing of a new cyclic well for up to 180 days from each production zone for the purpose of determining the viability of developing a steam-enhanced production zone.

3.2~~6~~7 Portable Hydrocarbon Detection Instrument: a hand-held hydrocarbon analyzer that meets the criteria specified in EPA Method 21, 40 CFR Part 60. The instrument shall be calibrated on methane.

3.2~~7~~8 Pressure Relief Device (PRD): a pressure relief valve, ~~or~~ a rupture disk~~.~~, or an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere.

~~3.289~~ ~~Pressure Relief Valve (PRV): an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere (atmospheric PRV).~~

3.29 Process Drain: an open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources. Drain origination points and drain termination points are not open-ended lines. Process drains are not open-ended lines.

3.30 Process System: an APCO-approved system that is not open to the atmosphere and is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gases or vapors from a piece of equipment to a process stream, fuel gas system, sales gas system or an injection well approved by the ~~Department of Oil, Gas, and Geothermal Resources (DOGGR)~~ California Geologic Energy Management Division (CalGEM).

3.31 Process Unit: a manufacturing process which is independent of other processes and is continuous when supplied with a constant feed of raw material and sufficient storage facilities for the final product.

3.32 Production Zone: a subsurface geologic formation or group of formations of oil-bearing material through which steam could migrate from a steam injection well, or cyclic well being steamed to an oil production well.

3.33 Pump: a device used to transport fluids by the addition of energy, and includes all associated components used for connecting or sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the pump. For example, a valve that is connected to a threaded hole on the body of the pump, the first VOC leak point is the threaded connection on the body side of the pump, but the valve itself is not a "first VOC leak point". Similarly, a pump shaft seal is considered as a “first VOC leak point”.

3.34 Release: a VOC emission to the atmosphere from a PRD caused by an increase in upstream pressure. A leak caused by improper reseating of the PRD is not a release.

3.35 Rig-up Operation: an activity requiring any rig or pulling unit used for drilling and maintaining surface or downhole well equipment.

3.3~~5~~6 Rupture Disk: a rigid diaphragm held between flanges for the purpose of isolating organic compounds from the atmosphere or from a downstream pressure relief ~~valve~~ device. Rupture disks are designed to fail at a certain pressure point.

3.3~~6~~7 Service or Repair: a well shall be considered under service or repair during rig-up, operation, and rig-down of any rig or pulling unit used to repair or maintain surface or downhole well equipment.

3.3~~7~~8 Sight glass: a device located on a fluid line or a process vessel that allows an operator to view the product or material inside a fluid line or a process vessel.

3.3~~8~~9 Small Producer: a person who produces a monthly average of less than 6,000 barrels of crude oil per day from all operations in any one county within the District, and who does not engage in refining, transporting, or marketing of refined petroleum products. An operator shall qualify as a small producer only in the county where the operator's crude oil production does not exceed the threshold specified above.

3.3~~9~~40 Steam Drive Well: a crude oil production well which produces from the same production zone in which a steam injection well is completed and is within:

3.3~~9~~40.1 250 feet of a steam injection well, if the injection well is within a production well pattern of two and one-half (2 1/2) acres or smaller, or

3.3~~9~~40.2 350 feet of a steam injection well, if the injection well is within a production well pattern of greater than two and one-half (2 1/2) acres but less than or equal to five (5) acres, or

3.3~~9~~40.3 500 feet of a steam injection well, if the injection well is within a production well pattern larger than five (5) acres, or

3.3~~9~~40.4 1000 feet of a steam injection well, and responds to steam injected in an irregular production well pattern, and exhibits any visible emissions.

3.4~~0~~1 Steam-Enhanced Crude Oil Production Well: a steam drive well, cyclic well, or any other well in which the temperature of crude oil is raised, by the injection of steam, above the production zone temperature that existed prior to the injection of steam.

3.4~~1~~2 Steam Injection Well: a well into which steam is injected that enhances the production of oil from other wells in the same production zone. Cyclic wells which enhance production of oil from other wells in the production zone are considered injection wells.

3.4~~2~~3 Tag: a piece of paper, metal, plastic or other suitable material that is attached to a component for the purpose of identification or other information.

3.4~~3~~4 True Vapor Pressure (TVP): as defined in Rule 4623 (Storage of Organic Liquids).

3.4~~4~~5 Turnaround: a scheduled shutdown of a process unit for maintenance and repair work.

3.4~~5~~6 Unsafe-to-Monitor Component: a component installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.

3.4~~6~~7 Vacuum Service: operating under a negative gauge pressure or below atmospheric pressure.

3.4~~7~~8 Valve: a device that regulates the flow of fluid in a piping system by means of an external actuator acting to permit or block passage of fluid.

3.4~~8~~9 Visible Emissions: from well vents, visible emissions are any visible plume including water vapor. When the ambient air temperature is 60°F or less a well vent shall be considered to have visible emissions if there is any visible plume and there is a leak as defined above.

3.4~~9~~50 Volatile Organic Compound (VOC): as defined in Rule 1020 (Definitions).

3.5~~0~~1 VOC Collection and Control System: an APCO-approved system that is not open to the atmosphere and that is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gas or vapor from a piece or pieces of equipment to an APCO-approved control device that has a VOC destruction or removal efficiency of at least 99%, that transports gases or vapors back to a process system.

3.5~~1~~2 VOC Emissions: emissions resulting from the operation of a steam-enhanced crude oil production well. Such emissions include uncondensed casing vent emissions and any emissions resulting from the handling, transfer, storage, or disposal of condensed and uncondensed casing vapors.

3.5~~2~~3 Well Stimulation: cyclic steam injection of a well for up to 180 days prior to the well being placed in service as a continuous steam injection well.

3.5~~3~~4 Well Vent: an opening on a well head that facilitates or blocks the flow of well casing vapors to the atmosphere or to a VOC collection and control system.

4.0 Exemptions

4.1 Any steam-enhanced crude oil production well undergoing service or repair during the time the well is not producing.

4.2 The requirements of this rule for cyclic wells shall not apply to up to 40 wells owned by a company and undergoing pilot testing provided;

4.2.1 the production zone on that property has not been injected with steam during the preceding two (2) years,

4.2.2 the well is located more than 1000 feet from an existing well vent vapor collection and control system operated by the company, and

4.2.3 the operation is under District permit.

4.3 The requirements of this rule shall not apply to up to 40 cyclic wells owned by a company and undergoing well stimulation, provided;

4.3.1 the well is located more than 1000 feet from an existing well vent vapor collection and control system operated by the company, and

4.3.2 the operation is under District permit.

4.4 The requirements of this rule shall not apply to up to five (5) cyclic wells owned by a company that is not a small producer, in each stationary source as defined in Rule 2201 (New and Modified Stationary Source Review Rule), and up to 20 cyclic wells owned by a small producer, provided the requirements of Section 4.4.1 and Section 4. 4.2 are met.

4.4.1 the well is located more than 1000 feet from an existing well vent vapor control system operated by the company, and

4.4.2 the operation is under District permit.

4.5 The requirements of this rule shall not apply to components serving the produced fluid line.

4.6 Except for complying with the applicable requirements of Section 6.1, Section 6.6.6 and Section 7.2, the requirements of this rule shall not apply to components described in Section 4.6.1 through Section 4.6.4<u>3</u>. An operator claiming an exemption pursuant to Section 4.6 shall provide proof of the applicable criteria to the satisfaction of the APCO.

4.6.1 Pressure relief devices, pumps, and compressors that are enclosed and whose emissions are controlled with an operating VOC collection and control system as defined in Section 3.0.

4.6.2 Components buried below ground.

4.6.3 Components used exclusively in vacuum service.

~~4.6.4 One-half inch nominal or less stainless steel tube fittings which have been demonstrated to the APCO to be leak-free based on initial inspection using the test method specified in Section 6.3.3.~~

~~4.7 The requirements of Section 5.4.1 through Section 5.4.7 of this rule shall not apply to components exclusively handling gas/vapor or liquid with a VOC content of ten percent by weight or less (≤10 wt.%), as determined by the test methods in Section 6.3.4.~~

5.0 Requirements

5.1 An operator shall not operate a steam-enhanced crude oil production well unless the operator complies with the requirements of either Section 5.1.1 or Section 5.1.2.

5.1.1 The steam-enhanced crude oil production well vent is closed and the front line production equipment downstream of the wells that carry produced fluids (crude oil or mixture of crude oil and water) is connected to a VOC collection and control system as defined in Section 3.0. The well vent may be temporarily opened during periods of attended service or repair of the well provided such activity is done as expeditiously as possible with minimal spillage of material and VOC emissions to the atmosphere.

5.1.2 The steam-enhanced crude oil production well vent is open and the well vent is connected to a VOC collection and control system as defined in Section 3.0.

5.2 Determination of Compliance with the Leak Standards

An operator shall comply with the following:

5.2.1 An operator shall be in violation of this rule if any District inspection demonstrates that one or more of the conditions in Section 5.2.2 exist at the facility or if any operator inspection conducted pursuant to Section 5.4 demonstrates that one or more of the conditions in Section 5.2.2 exist at the facility.

5.2.2 Leak Standards

The following conditions shall be used for determination of violation during an inspection pursuant to the provisions of Section 5.2.1.

5.2.2.1 Existence of an open-ended line or a valve located at the end of the line that is not sealed with a blind flange, plug, cap, or a second closed valve that is not closed at all times, except during attended operations requiring process fluid flow through the open-ended lines. Attended operations include draining or degassing operations, connection of temporary process equipment, sampling of process streams, emergency venting, and other normal operational needs, provided such operations are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

5.2.2.2 Existence of a component with a major liquid leak as defined in Section 3.0.

5.2.2.3 Existence of a component with a gas leak greater than 50,000 ppmv.

5.2.2.4 Existence of a component leak described in Section 5.2.2.4.1 through Section 5.2.2.4.3 in excess of the allowable number of leaks specified in Table ~~2~~3 or Table 4.

5.2.2.4.1 A minor liquid leak, or

5.2.2.4.2 A minor gas leak, or

5.2.2.4.3 A gas leak greater than 10,000 ppmv up to 50,000 ppmv.

Table ~~2~~3 – Number of Allowable Leaks until June 30, 2024	
Number of Steam-Enhanced Crude Oil Production Wells Connected to a VOC Collection and Control System	Number of Allowable Leaks
1to 25	3
26 to 50	6
51 to 100	8
101 to 250	10
251 to 500	15
More than 500	One (1) for each 20 wells tested with a minimum of 50 wells tested.

*Leaks counted toward the allowable leaks in Table 3 are still subject to component repair requirements of section 5.5.

Table 4 – Number of Allowable Leaks after June 30, 2024	
Number of Steam-Enhanced Crude Oil Production Wells Connected to a VOC Collection and Control System	Number of Allowable Leaks
1 to 5	0
6 to 25	3
26 to 50	6
51 to 100	8
101 to 250	10
251 to 500	15
More than 500	One (1) for each 20 wells tested with a minimum of 50 wells tested.

*Leaks counted toward the allowable leaks in Table 4 are still subject to component repair requirements of section 5.5.

5.3 An operator shall comply with the following operating requirements:

5.3.1 An operator shall not use any component with a leak as defined in Section 3.0, or that is found to be in violation of the provisions of Section 5.2.2. However, components that were found leaking may be used provided such leaking components have been identified with a tag for repair, are repaired, or awaiting re-inspection after being repaired within the applicable time frame specified in Section 5.5 of this rule.

5.3.2 Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible with minimal spillage of material and VOC emissions to the atmosphere.

5.3.3 An operator shall comply with the requirements of Section 6.7 if there is any change in the description of major components or critical components.

5.4 Inspection and Re-inspection Requirements

Unless otherwise specified, an operator shall perform all component inspections and gas leak measurements pursuant to the requirements of Section 6.3.3.

5.4.1 Until June 30, 2024, ~~E~~except for pipes and unsafe-to-monitor components, an operator shall inspect all other components pursuant to the requirements of Section 6.3.3 at least once every year.

5.4.2 After June 30, 2024, except for pipes and unsafe-to-monitor components, an operator shall inspect all other components pursuant to the requirements of Section 6.3.3 at least once every calendar quarter.

5.4.~~2~~3 An operator shall visually inspect all pipes at least once every year. Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected within 24 hours after detecting the leak. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table ~~3~~5 of this rule.

5.4.~~3~~4 In addition to the inspections required by Section 5.4.1, an operator shall inspect for leaks all accessible operating pumps, compressors, and PRDs in service as follows:

5.4.~~3~~4.1 An operator shall audio-visually (by hearing and by sight) inspect for leaks all accessible operating pumps, compressors, and PRDs in service at least once each calendar week.

5.4.~~3~~4.2 Any audio-visual inspection of an accessible operating pump, compressor, and PRD performed by an operator that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected not later than 24 hours after conducting the audio-visual inspection. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table ~~3~~5 of this rule.

5.4.4~~5~~ In addition to the inspections required by Section 5.4.1, Section 5.4.~~2~~3 and Section 5.4.~~3~~4, an operator shall perform the following inspections:

5.4.4~~5~~.1 An operator shall initially inspect a PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the discovery of the release. An operator shall re-inspect the PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the initial inspection.

5.4.4~~5~~.2 An operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 72 hours of placing the component in service.

5.4.4~~5~~.3 Except for PRDs subject to the requirements of Section 5.4.4~~5~~.1, an operator shall inspect a component that has been repaired or replaced not later than 15 calendar days after the component was repaired or replaced.

5.4.~~5~~6 An operator shall inspect all unsafe-to-monitor components during each turnaround.

5.4.~~6~~7 A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator.

5.5 Leak Repair Requirements

5.5.1 An operator shall affix a readily visible weatherproof tag to all leaking components upon detection of the leak. An operator shall include the following information on the tag:

5.5.1.1 The date and time of leak detection.

5.5.1.2 The date and time of leak measurement.

5.5.1.3 For a gaseous leak, the leak concentration in ppmv.

5.5.1.4 For a liquid leak, whether it is a major liquid leak or a minor liquid leak.

5.5.1.5 Whether the component is an essential component, an unsafe-to-monitor component, or a critical component.

5.5.2 An operator shall keep the tag affixed to the component until an operator has met all of the following conditions:

5.5.2.1 Repaired or replaced the leaking component, and

5.5.2.2 Re-inspected the component using the test method in Section 6.3.3, and

5.5.2.3 The component is found to be in compliance with the requirements of this rule.

5.5.3 An operator shall minimize a component leak in order to stop or reduce leakage to the atmosphere immediately to the extent possible, but not later than one (1) hour after detection of the leak.

5.5.4 Except for leaking critical components or leaking essential components subject to the requirements of Section 5.5.7, if an operator has minimized a leak but the leak still exceeds the applicable leak limits as defined in Section 3.0, an operator shall comply with at least one of the requirements of Section 5.5.4.1, Section 5.5.4.2, or Section 5.5.4.3 as soon as practicable but not later than the time period specified in Table ~~3~~5 or Table 6.

5.5.4.1 Repair or replace the leaking component; or

5.5.4.2 Vent the leaking component to a VOC collection and control system as defined in Section 3.0, or

5.5.4.3 Remove the leaking component from operation.

Table ~~3~~5 – Repair Period until June 30, 2024	
Type of Leak	Repair Period in Calendar Days
Gas Leaks	
Minor Gas Leak	14
Major Gas Leak less than or equal to 50,000 ppmv	5
Gas Leak greater than 50,000 ppmv	2
Liquid Leaks	
Minor Liquid Leak	3
Major Liquid Leak	2

Table 6 – Repair Period after June 30, 2024	
Type of Leak	Repair Period in Calendar Days
Gas Leaks	
Minor Gas Leak	14
Major Gas Leak less than or equal to 50,000 ppmv	5
Gas Leak greater than 50,000 ppmv	1
Liquid Leaks	
Minor Liquid Leak	3
Major Liquid Leak	1

5.5.5 The leak rate measured after leak minimization has been performed shall be ~~Open~~ the leak rate used to determine the applicable repair period specified in Table ~~3~~5.

5.5.6 The time of the initial leak detection shall be the start of the repair period specified in Table ~~3~~5 or Table 6.

5.5.7 If the leaking component is an essential component or a critical component that cannot be immediately shut down for repairs, and if the leak has been minimized but the leak still exceeds the applicable leak standard of this rule, the operator shall repair or replace the essential component or critical component to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier.

5.5.8 After June 30, 2024, if a leaking component requires rig-up operation to complete repair, an extended repair period may be granted for up to 30 calendar days from initial leak detection under the following conditions:

5.5.8.1 The operator shall provide written notification to the District within the compliant repair period. Notification shall include the following:

5.5.8.1.1 The Permit to Operate (PTO) number and physical location of the well being repaired.

5.5.8.1.2 The date and time the component was found to be leaking and the leak concentration.

5.5.8.1.3 Proof that equipment or other required services necessary to make the repairs have been ordered or scheduled.

5.5.8.2 The operator shall submit a written notification to the District within seven (7) calendar days of completing the repairs and re-inspecting the component using the test method listed in Section 6.3.3.

5.5.8.3 Operators who fail to comply with all of the requirements specified in Sections 5.5.8.1 and 5.5.8.2 shall be in violation with the provisions of this rule.

6.0 Administrative Requirements

6.1 Recordkeeping and Submissions

An operator shall maintain the records required by Section 6.1 and Section 6.2 for a period of five (5) years. These records shall be made available to the APCO, California Air Resources Board (ARB), and EPA upon request.

6.1.1 The operator of any steam-enhanced crude oil production well shall maintain records of the date and well identification where steam injection or well stimulation occurs.

6.1.2 A small producer shall maintain monthly records of county-specific crude oil production. For the purpose of this rule, the monthly crude oil production records required by the ~~California Division of Oil, Gas, and Geothermal Resources~~ California Geologic Energy Management Division (CalGEM) may be used to satisfy Section 6.1.2.

6.1.3 An operator of any steam-enhanced crude oil production well shall keep source test records which demonstrate compliance with the control efficiency requirements of the VOC collection and control system as defined in Section 3.0.

6.1.4 The inspection log maintained pursuant to Section 6.4.

6.1.5 Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.

6.1.6 An operator shall maintain copies at the facility of the training records of the training program operated pursuant to Section 6.5.

6.1.7 An operator shall keep a copy of the APCO-approved Operator Management Plan at the facility.

6.1.8 An operator shall keep a list of all gauge tanks, as defined in Section 3.0. The list shall contain the size, identification number, the location of each gauge tank and specify whether the gauge tank is upstream of all front line production equipment.

6.1.9 The results of gauge tank TVP testing conducted pursuant to Section 6.2.3 shall be submitted to the APCO within 60 days after the completion of the testing.

6.1.10 An operator that discovers that a PRD has released shall record the date that the release was discovered, and the identity and location of the PRD that released. An operator shall submit such information recorded during the calendar year of the release to the APCO no later than 60 days after the end of the calendar year.

6.2 Compliance Source Testing

6.2.1 An operator shall source test ~~annually~~ each calendar year all VOC collection and control systems used to control emissions from steam-enhanced crude oil

production well vents to determine the control efficiency of the device(s) used for destruction or removal of VOC. Compliance testing shall be performed at least ~~annually~~ each calendar year by source testers certified by ARB. Testing shall be performed during June, July, August, or September of each year if the system's control efficiency is dependent upon ambient air temperature. A process system is not subject to compliance source testing requirements.

6.2.2 If approved by the APCO, a VOC collection and control system is not subject to Section 6.2.1 if all uncondensed VOC emissions collected by the system are controlled by a device meeting one of the requirements in Sections 6.2.2.1 through 6.2.2.3.

6.2.2.1 An internal combustion engine subject to District Rule 4702 (Internal Combustion Engines – Phase 2); or

6.2.2.2 A combustion device subject to District Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr); District Rule 4307 (Boilers, Steam Generators, and Process Heaters – 2.0 MMBtu/hr to 5.0 MMBtu/hr); or District Rule 4308 (Boilers, Steam Generators, and Process Heaters – 0.075 MMBtu/hr to 2.0 MMBtu/hr); or

6.2.2.3 A unit subject to District Rule 4311 (Flares).

6.2.3 An operator shall comply with the following requirements for each gauge tank, as defined in Section 3.0:

6.2.3.1 An operator shall conduct periodic TVP testing of each gauge tank at least once every 24 months during summer (July – September), and whenever there is a change in the source or type of produced fluid in the gauge tank.

6.2.3.2 The TVP testing shall be conducted at the actual storage temperature of the produced fluid in the gauge tank using the applicable TVP test method specified in Section 6.4 of Rule 4623 (Storage of Organic Liquids). The operator shall submit the TVP testing results to the APCO as specified in Section 6.1.9.

6.3 Test Methods

Test methods that are equivalent to those test methods specified in Section 6.3.1 through Section 6.3.45 may be used provided that such equivalent test methods have been previously approved, in writing, by the EPA, ARB, and the APCO.

6.3.1 The control efficiency of any VOC control device, measured and calculated as carbon, shall be determined by EPA Method 25, except when the outlet concentration must be below 50 ppm in order to meet the standard, in which case EPA Method 25a may be used. EPA Method 18 may be used in lieu of EPA Method 25 or EPA Method 25a provided the identity and approximate concentrations of the analytes/compounds in the sample gas stream are known before analysis with the gas chromatograph and the gas chromatograph is calibrated for each of those known analyte/compound to ensure that the VOC concentrations are neither under- or over-reported.

6.3.2 VOC content shall be analyzed by using the latest revision of ASTM Method E168, E169, or E260 as applicable. Analysis of halogenated exempt compounds shall be performed by using ARB Method 432.

6.3.3 Leak inspection, other than audio-visual, and measurements of gaseous leak concentrations shall be conducted according to EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. Where safety is a concern, such as measuring leaks from compressor seals or pump seals when the shaft is rotating, a person shall measure leaks by placing the instrument probe inlet at a distance of one (1) centimeter or less from the surface of the component interface.

6.3.3.1 <u>After June 30, 2024, All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 6.</u>

6.3.4 The VOC content by weight percent (wt.%) shall be determined using American Society of Testing and Materials (ASTM) D1945 for gases and South Coast Air Quality Management District (SCAQMD) Method 304-91 or the latest revision of ASTM Method E168, E169 or E260 for liquids.

6.4 Inspection Log

An operator shall maintain an inspection log in which an operator records, at a minimum, all of the following information for each inspection performed:

6.4.1 The total number of components inspected, and the total number and percentage of leaking components found by component type.

6.4.2 The location, type, and name or description of each leaking component and description of any unit where the leaking component is found.

6.4.3 The date of leak detection and the method of leak detection.

6.4.4 For gaseous leaks, the leak concentration in ppmv, and for liquid leaks record whether the leak is a major liquid leak or a minor liquid leak.

6.4.5 The date of repair, replacement, or removal from operation of leaking components.

6.4.6 The identify and location of essential components and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes earlier.

6.4.7 The methods used to minimize the leak from essential components and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes earlier.

6.4.8 The date of re-inspection and the leak concentration in ppmv after the component is repaired or is replaced.

6.4.9 The inspector's name, business mailing address, and business telephone number.

6.4.10 The date and signature of the facility operator responsible for the inspection and repair program certifying the accuracy of the information recorded in the log.

6.5 Employee Training Program

An operator shall establish and implement an employee training program for inspecting and repairing components and recordkeeping procedures, as necessary.

6.6 Operator Management Plan

~~By June 30, 2008, a~~An operator whose existing wells are subject to this rule or whose existing wells are exempt pursuant to Section 4.0 of this rule ~~on or before December 14, 2006~~ shall prepare and submit an Operator Management Plan for approval by the APCO. An operator may use diagrams, charts, spreadsheets, or other methods approved by the APCO to describe the information required by Section 6.6.4 through Section 6.6.7 below. The Operator Management Plan shall include, at a minimum, all of the following information:

6.6.1 A description of all wells and all associated VOC collection and control systems subject to this rule, and all wells and all associated VOC collection and control systems that are exempt pursuant to Section 4.0 of this rule.

6.6.2 Identification and description of any known hazard that might affect the safety of an inspector.

6.6.3 Except for pipes, the number of components that are subject to this rule by component type.

6.6.4 Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components that are subject to this rule and the reason(s) for such designation.

6.6.5 Except for pipes, the location of components subject to the rule (components may be grouped together functionally by process unit or facility description).

6.6.6 Except for pipes, components exempt pursuant to Section 4.6 (except for components buried below ground) may be described in the Operator Management Plan by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the applicable exemption criteria for components for which an exemption is being claimed pursuant to Section 4.6 shall be submitted with the Operator Management Plan.

6.6.7 A detailed schedule of an operator's inspections of components to be conducted as required by this rule and whether the operator inspections of components required by this rule will be performed by a qualified contractor or by an in-house team.

6.6.8 A description of the training standards for personnel that inspect and repair components.

6.6.9 A description of the leak detection training for conducting the test method specified in Section 6.3.3 for new operators, and for experienced operators, as necessary.

6.7 By January 30 of each year, an operator shall submit to the APCO for approval, in writing, an annual report indicating any or no changes to an existing Operator Management Plan.

6.8 The APCO shall provide written notice to the operator of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Operator Management Plan. If the APCO fails to respond in writing within 60 days after the date of receiving the Operator Management Plan, it shall be

deemed approved. No provision of the Operator Management Plan, approved or not, shall conflict with or take precedence over any provision of this rule.

7.0 Compliance Schedule

7.1 The operator of any new steam-enhanced crude oil production well, or any non-steam-enhanced crude oil production well converted to a steam-enhanced crude oil production well shall comply with the requirements of this rule and the applicable permit requirements of Rule 2201 (New and Modified Stationary Source Review Rule) before steam injection and no later than the first detectable flow at the casing vent.

7.2 Steam-enhanced crude oil production wells and components that are exempt pursuant to Section 4.2, 4.3, 4.4, or 4.6~~, or 4.7~~ that become subject to this rule through loss of exemption status shall not be operated until such time that they are in full compliance with the requirements of this rule.

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RULE 4409 COMPONENTS AT LIGHT CRUDE OIL PRODUCTION FACILITIES, NATURAL GAS PRODUCTION FACILITIES, AND NATURAL GAS PROCESSING FACILITIES (Adopted April 20, 2005; Amended [*rule adoption date*])

1.0 Purpose

The purpose of this rule is to limit Volatile Organic Compound (VOC) emissions from leaking components at light crude oil production facilities, natural gas production facilities, and natural gas processing facilities.

2.0 Applicability

This rule shall apply to components containing or contacting VOC streams at light crude oil production facilities, natural gas production facilities, and natural gas processing facilities.

3.0 Definitions

3.1 APCO: The Air Pollution Control Officer of the San Joaquin Valley Unified Air Pollution Control District, or any person authorized to act on behalf of the APCO.

3.2 ARB: California Air Resources Board as established by the California Health and Safety Code Section 39510, or any person authorized to act on its behalf

3.3 Background: a reading on a portable hydrocarbon detection instrument which is determined at a distance no greater than two (2) meters upwind from any component to be inspected and which is uninfluenced by any specific emission point.

3.4 Closed-vent System: a APCO-approved system that is not open to the atmosphere and that is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gas or vapor from a piece or pieces of equipment to an APCO-approved control device that has a overall VOC collection and destruction or removal efficiency of at least 95%, or that transports gases or vapors back to a process system.

3.5 Commercial Quality Natural Gas: a mixture of gaseous hydrocarbons with at least 80 percent methane by volume (≥ 80 vol%) and less than ten percent by weight (<10 wt%) VOC, as determined according to test methods specified in Section 6.3.~~2~~3, and meets the criteria specified in Public Utilities Commission (PUC) General Order 58-A.

3.6 Component: includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, polished rod stuffing box, flange, process drain, sealing mechanism, hatch, sight-glass, meter or seal fluid system in VOC service.

3.6.1 Major Component: any pump 5 brake horsepower or larger, any compressor, and any pressure relief ~~valve~~ device 4 inches in diameter or larger.

~~3.6.2 Minor Component: any component that is not a major component.~~

3.7 Component Type: includes, but is not limited to, any one (1) of the following groups: valves, fittings, threaded connections, pumps, compressors, pressure relief devices, pipes, polished rod stuffing boxes, flanges, process drains, sealing mechanisms, hatches, sight-glasses, meters, or seal fluid systems in VOC service.

3.8 Compressor: a device used to compress gases or vapors or a combination of gases and vapors by the addition of energy, and includes all associated components used for connecting and sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) connected on the body of the compressor. For example, a valve that is connected to a threaded hole on body of the compressor, the first VOC leak point is the threaded connection on the body side of the compressor, but the valve itself is not a "first VOC leak point". Similarly, a compressor shaft seal is considered as a first “VOC leak point”.

3.9 Compressor Part: for the purpose of Section 5.3.7, a compressor part refers to the “first VOC leak point” as explained in Section 3.8.

3.10 Critical Component: any component that would require the shutdown of a critical process unit if that component was shut down or disabled.

3.11 Critical Process Unit: a process unit that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

3.12 Critical Process Unit Shutdown: the shutdown of a critical process unit or part of the critical process unit that causes the entire unit to cease operating.

3.13. District: San Joaquin Valley Unified Air Pollution Control District.

3.14 Essential Component: a component that cannot be taken out of service without reducing, by more than 33 percent, the throughput of the process unit that it serves.

3.15 Facility: a stationary source as defined in Rule 2201 (New and Modified Stationary Source Rule).

3.16 Fitting: a component, excluding flanges and threaded connectors, used to attach or connect pipes or piping system. Examples of a "fitting" include, but are not limited to quick-disconnect fitting, push-in-fittings, and cam-locks.

3.17 Gas/Vapor Service: a component is considered to be in gas/vapor service when the fluid in contact with the component contains VOCs and the fluid is primarily in gaseous state at operating conditions.

3.18 Inaccessible Component: a component that is located over 15 feet above ground when access is required from the ground; or a component that is located over six (6) feet away from a platform when access is required from the platform, or a component in a location that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.

3.19 Inspection: checking and/or testing in order to detect leaks.

3.19.1 Operator Inspection: inspection of components conducted by the operator pursuant to the inspection and re-inspection schedules specified in this rule for the purpose of demonstrating compliance with this rule.

3.19.2 District Inspection: inspection of components by District personnel or their representative to insure facilities and/or operators are in compliance with District requirements.

3.20 Leak: the dripping of VOC-containing liquid or the detection of a concentration of total organic compound, above background, determined according to the test method specified in Section 6.3.1 that exceeds the values specified in Table 1 or Table 2, Sections 3.20.1, and Section 3.20.2 of this rule. Any liquid or gas coming from a component undergoing repair or replacement, or during sampling of process fluid from a component into a container is not considered a leak provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

Table 1 – Gas Leak Standards in ppmv as Methane until June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
2. Threaded Connections	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
3. Flanges	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
4. Pipes	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
5. Pumps	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
6. Compressors	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
7. PRDs	Greater than 10,000	200 to 10,000	400 to 10,000
8. Polished Rod Stuffing Boxes	Greater than 10,000	1,000 to 10,000	1,000 to 10,000
9. ~~Other~~ Components not listed in ~~items 1, 2, 3,4, 5, 6,7, and 8~~ 1 through 8 above	Greater than 10,000	1,000 to 10,000	2,000 to 10,000

Table 2 – Gas Leak Standards in ppmv as Methane after June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Components other than PRDs	Greater than 10,000	500 to 10,000	500 to 10,000
2. PRDs	Greater than 10,000	200 to 10,000	400 to 10,000

3.20.1 Major Liquid Leak: a visible mist or a continuous flow of liquid that is not seal lubricant.

3.20.2 Minor Liquid Leak: a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute.

3.21 Leak Minimization: reducing a leak to the lowest achievable level without damaging the component using best modern practices which include, but are not limited to, adding sealing material to the component, tightening the component, or adjusting the component without shutdown of the process that the component serves and that can be safely accommodated.

3.22 Light Crude Oil: crude oil with API gravity equal to or greater than 30 degrees and a true vapor pressure (TVP) greater than 1.5 psia as determined by the test methods specified in Section 6.3.45.

3.23 Light Crude Oil Production Facility: that portion of a crude oil production facility at which light crude oil production and handling are conducted, as defined in the North

American Industry Classification System 211111 (Crude Petroleum and Natural Gas Extraction).

3.24 Liquid Service: a component is considered to be in liquid service when the fluid in contact with the component contains VOCs and the fluid is primarily liquid at operating conditions.

3.25 Natural Gas Processing Facility: a facility engaged in the separation of natural gas liquids from field gas and/or fractionating of natural gas liquids to natural gas products, such as ethane, propane, butane, and natural gasoline. Excluded from the definition are compressor stations, dehydration units, sweetening units, field treatment, underground storage facilities, liquefied natural gas units, and field gas gathering systems unless these facilities are located at a natural gas processing facility. For the purpose of this rule, a gas liquids processing facility as defined in Rule 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants) is not considered a natural gas processing facility.

3.26 Natural Gas Production Facility: that portion of a gas production facility at which natural gas production and handling are conducted, as defined North American Industry Classification System (NAICS) as Industry No. 211111 (Crude Petroleum and Natural Gas Extraction).

3.27 Open-ended Line or Valve: any line or valve, except for pressure relief devices ~~PRV~~ and process drains, having one side of the line or valve seat in contact with the process fluid and one side open to the atmosphere, either directly or through an open piping.

3.28 Optical Gas Imaging (OGI): an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

3.2~~8~~9 Portable Hydrocarbon Detection Instrument: a hand-held hydrocarbon analyzer that meets the criteria specified in US EPA Method 21, 40 CFR Part 60. The instrument shall be calibrated with methane.

3.2~~9~~30 Pressure Relief Device (PRD): a pressure relief valve, ~~or~~ a rupture disc, or an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere.

~~3.30 Pressure Relief Valve (PRV): an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere (atmospheric PRV).~~

3.31 Process Drain: any open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources. Drain origination points

and drain termination points are not open-ended lines. Process drains are not open-ended lines.

3.32 Process System: an APCO-approved system that is not open to the atmosphere and is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gases or vapors from a piece of equipment to a process stream, fuel gas system, or sales gas system.

3.33 Pump: a device used to transport fluids by the addition of energy, and includes all associated components used for connecting or sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the pump. For example, a valve that is connected to a threaded hole on body of the pump, the first VOC leak point is the threaded connection on the body side of the pump, but the valve itself is not a "first VOC leak point". Similarly, a pump shaft seal is considered as a first "VOC leak point".

3.34 Pump Part: for the purpose of Section 5.3.7, a pump part refers to the "first VOC leak point" as explained in Section 3.33.

3.35 Release: a VOC emission to the atmosphere from PRD caused by an increase in upstream pressure. A leak caused by improper reseating of the PRD is not a release.

3.36 Rig-up Operation: an activity requiring any rig or pulling unit used for drilling and maintaining surface or downhole well equipment.

3.3~~6~~7 Rupture Disk: a rigid diaphragm held between flanges for the purpose of isolating organic compounds from the atmosphere or from a downstream pressure relief ~~valve~~ device. Most rupture disks are designed to fail at a certain pressure point.

3.3~~7~~8 Sight glass: a device located on a fluid line or a process vessel that allows an operator to view the product or material inside a fluid line or a process vessel.

3.3~~8~~9 Tag: a piece of paper, metal, plastic or other suitable material that is attached to a component for the purpose of identification or other information.

3.~~39~~40 True Vapor Pressure (TVP): the equilibrium partial vapor pressure exerted by an organic liquid at actual storage temperature as determined by the applicable test methods specified in Section 6.3.

3.4~~0~~1 Turnaround: scheduled shutdown of a process unit for maintenance and repair work.

3.4~~1~~2 Unmanned Facility: a facility which has no permanent-sited operators. Permanent-sited operators means personnel responsible for the operation of the equipment subject to this rule is in attendance at the facility 24 hours per day.

3.4~~2~~3 Unsafe-to-Monitor Component: a component installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.

3.4~~3~~4 US EPA: United States Environmental Protection Agency

3.4~~4~~5 Vacuum Service: operating under a negative gauge pressure or below atmospheric pressure.

3.4~~5~~6 Valve: a device that regulates the flow of fluid in a piping system by means of an external actuator acting to permit or block passage of fluid.

3.4~~6~~7 Volatile Organic Compound (VOC): as defined in Rule 1020 (Definitions).

4.0 Exemptions

4.1 The requirements of this rule shall not apply to components subject to Rule 4623 (Storage of Organic Liquids); to components included in the inspection and maintenance (I&M) program implemented pursuant to Section 5.7 of Rule 4623; or to components subject to Rule 4401 (Steam Enhanced Crude Oil Production Well Vents).

4.2 Except for complying with the applicable requirements of Sections 6.1 and 7.~~3~~1, the requirements of this rule shall not apply to components described in Sections 4.2.1 through 4.2.~~10~~9. An operator claiming an exemption pursuant to Section 4.2 shall provide proof of the applicable criteria to the satisfaction of the APCO.

4.2.1 Pressure relief devices, pumps, and compressors equipped with a closed-vent system as defined in Section 3.0.

4.2.3 Components buried below ground.

4.2.4 Components exclusively handling liquid streams which have less than 10 percent by weight (<10 wt%) evaporation at 150^0 C as determined by the test method specified in Section 6.3.~~3~~4.

4.2.5 Components handling liquids with 90 percent by volume or greater (≥90 vol%) water concentration if the components are located after initial oil/water separation.

4.2.6 Components at oil production facilities and gas production facilities exclusively handling gas/vapor or liquid with a VOC content of ten percent by weight or less (≤10 wt%), as determined by the test methods in Section 6.3.~~2~~3.

4.2.7 Components at natural gas processing facilities exclusively handling gas/vapor or liquid with a VOC content less than one percent by weight (<1 wt%) as determined by the test method specified in Section 6.3.~~2~~3.

4.2.8 Components exclusively in vacuum service.

4.2.9 Components handling commercial quality natural gas exclusively.

~~4.2.10 One-half inch nominal or less stainless steel tube fittings which have been demonstrated to the APCO to be leak-free based on initial inspection using the test method specified in Section 6.3.1.~~

5.0 Requirements

5.1 Operating Requirements:

5.1.1 An operator shall not use any component that leaks in excess of the applicable leak standards of this rule, or that is found to be in violation of the provisions specified in Section 5.1.3. Components that have been found leaking in excess of the applicable leak standards of this rule may be used provided such leaking components have been identified with a tag for repair, are repaired, or are awaiting re-inspection after being repaired, within the applicable time period specified in this rule.

5.1.2 Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

5.1.3 Determination of Compliance with the Leak Standards

5.1.3.1 District Inspection

5.1.3.1.1 The operator shall be in violation of this rule if any District inspection demonstrates that one or more of the conditions in Section 5.1.4 exist at the facility.

5.1.3.1.2 Notwithstanding the provision of Section 5.1.3.1.1, minor gas leaks from polished rod stuffing boxes (PRSB) found during any District inspection shall not be counted toward determination of compliance with this rule provided the operator repairs, replaces, or removes leaking PRSB from VOC service as soon as practicable but not later than the time frame specified in this rule.

5.1.3.2 Operator Inspection

5.1.3.2.1 Except for annual operator inspection described in Section 5.1.3.2.3, any operator inspection that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall not constitute a violation of this rule if the leaking components are repaired as soon as practicable but not later than the time frame specified in this rule. Such components shall not be counted towards determination of compliance with the provisions of Section 5.1.4.

5.1.3.2.2 Leaking components detected during operator inspection pursuant Section 5.1.3.2.1 that are not repaired, replaced, or removed from operation as soon as practicable but not later than the time frame specified in this rule shall be counted toward determination of compliance with the provisions of Section 5.1.4.

5.1.3.2.3 Any operator inspection conducted annually for a component type (including operator annual inspections pursuant to Section 5.2.6, 5.2.7, 5.2.8, or 5.2.9) that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall constitute a violation of this rule regardless of whether or not the leaking components are repaired, replaced, or removed from operation within the allowable repair time frame specified in this rule.

5.1.4 Leak Standards

For the purpose of this rule, a component shall be considered ~~leaking~~ in violation if one or more of the conditions specified in Sections 5.1.4.1 through 5.1.4.4 exist at the facility.

5.1.4.1 An open-ended line or a valve located at the end of the line that is not sealed with a blind flange, plug, cap, or a second ~~closed~~ valve that is not closed at all times, except during attended operations requiring process fluid flow through the open-ended lines. Attended operations include draining or degassing operations, connection of temporary process equipment, sampling of process streams, emergency venting, and other normal operational needs, provided such operations are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

5.1.4.2 A component with a major liquid leak.

5.1.4.3 A component with a gas leak greater than 50,000 ppmv.

5.1.4.4 A component leak described in Sections 5.1.4.4.1 through 5.1.4.4.3 and numbering in excess of the maximum allowable number or percent specified in Table ~~2~~3 until June 30, 2024, and Table 4 after June 30, 2024.

5.1.4.4.1 A minor liquid leak; or

5.1.4.4.2 A minor gas leak; or

5.1.4.4.3 A gas leak greater than 10,000 ppmv up to 50,000 ppmv.

Table ~~2~~3 – Maximum Allowable Number or Percent of Leaking Components
Per Inspection Period until June 30, 2024

Component	Maximum Number of Leaks for 200 or fewer Components Inspected*	Maximum Percent or Number of Leaks for more than 200 Components Inspected*
1. Valves	1	0.5% of number inspected
2. Threaded Connections	1	0.5% of number inspected
3. Flanges	1	0.5% of number inspected
4. Pumps	2	1.0% of number inspected
5. Compressors	1	1 leak
6. PRDs	1	1 leak
7. Polished Rod Stuffing Boxes	4	2.0% of number inspected
8. Other Components not listed in items 1, 2, 3, 4, 5, 6, 7, 9, and 10	1	1 leak
9. Pipes at Light Crude Oil Production Facilities or Gas Production Facilities	Maximum Number of Leaks for 200 or fewer production wells inspected	Maximum Number of Leaks for more than 200 production wells inspected
	2	1% of number inspected
10 Pipes at Natural Gas Processing Facilities	Maximum Number of Leaks	
	2	

*The maximum number of leaks in Table ~~2~~3 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components of a given type inspected during the specified inspection period. Leaks counted toward the allowable leaks in Table 3 are still subject to maintenance requirements of section 5.3.

Table 4 – Maximum Allowable Leaking Components
Per Inspection Period after June 30, 2024

	Leak Threshold 200 or Less Components Inspected	More than 200 Components Inspected
500 to 10,000 ppmv	5	2% of total inspected
10,000 to 50,000 ppmv	2	1% of total inspected

*The maximum number of leaks in Table 4 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components of a given type inspected during the specified inspection period. Leaks counted toward the allowable leaks in Table 4 are still subject to maintenance requirements of section 5.3.

5.2 Inspection and Re-inspection Requirements:

5.2.1 For manned light crude oil production facilities, natural gas production facilities, and gas processing facilities, an operator shall audio-visually (by hearing and by sight) inspect for leaks all accessible operating pumps,

compressors, pressure relief ~~valves~~ devices in service at least once every 24 hours except when operators do not report to the facility for that given 24 hours.

5.2.2 For unmanned light crude oil production facilities, natural gas production facilities, or gas processing facilities, the operator shall audio-visually inspect for leaks of all accessible operating pumps, compressors, PRDs in service at least once per calendar week.

5.2.3 Any audio-visual inspection of all accessible operating pumps, compressors, and PRDs performed by an operator that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected using the test method specified in Section 6.3.1 not later than 24 hours after conducting the audio-visual inspection. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table ~~3~~5 of this rule.

5.2.4 Notwithstanding the requirements of Sections 5.2.1, 5.2.2, and 5.2.3, the operator shall inspect all components using the test method specified in Section 6.3.1 at least once every calendar quarter, or as allowed by the following:

Inaccessible components and unsafe-to-monitor components shall be inspected in accordance with the provisions of Sections 5.2.6 and 5.2.7, respectively. Pipes shall be inspected in accordance with the provisions of Section 5.2.8.

5.2.5 The operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using the test method specified in Section 6.3.1.

5.2.6 The operator shall inspect all inaccessible components at least once every 12 months using the test method specified in Section 6.3.1.

5.2.7 The operator shall inspect all unsafe-to-monitor components during each turnaround using the test method specified in Section 6.3.1.

5.2.8 The operator shall visually inspect all pipes for leaks at least once every 12 months.

5.2.8.1 Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected using the test method specified in Section 6.3.1 within 24 hours after detecting the leak. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table ~~3~~5 of this rule.

5.2.8.2 The operator may conduct the annual pipe inspection required by Section 5.2.8 in conjunction with the annual pipe inspection required by the ~~Department of Oil, Gas, and Geothermal Resources (DOGGR)~~ California Geologic Energy Management Division (CalGEM). pursuant to California Code of Regulation Title 14, Division 2, Subchapter 2, Section 1774 (Oilfield Facilities and Equipment Maintenance), or by the Spill Prevention Control and Countermeasure Plan (SPCC) pursuant to 40 Code of Federal Regulation Part 112 (Oil Prevention and Response: Non-Transportation-Related Onshore and Offshore Facilities). Records of annual pipe inspection required by ~~DOGGR~~ CalGEM or SPCC may be used to document the inspection required by Section 5.2.8. The operator shall maintain the records of such inspections at the facilities. The records shall be made available to the APCO, ARB, and US EPA upon request.

5.2.9 Until June 30, 2024, ~~N~~notwithstanding the requirement of Section 5.2.4, the operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, or an operator who is already on an annual inspection frequency on or before (rule adoption date) may apply for a written approval from the APCO to continue conducting annual inspections for a component type, provided the operator meets all the criteria specified in Sections 5.2.9.1 through 5.2.9.3. This approval shall apply to all accessible components types specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis.

5.2.9.1 The operator was not in violation of any provision of Sections 5.1 during five consecutive quarterly inspections for that component type.

5.2.9.2 The operator did not receive a Notice of Violation from the APCO during the previous 12 months violating any provisions of this rule for that component type.

5.2.9.3 The written request shall include pertinent documentation to demonstrate that the operator has successfully met the requirements of Sections 5.2.9.1 and 5.2.9.2.

5.2.10 Until June 30, 2024, ~~T~~the annual inspection frequency approved by the APCO pursuant to Section 5.2.9 shall revert to quarterly inspection frequency for a component type if either one of the following occurs:

5.2.10.1 The operator inspection or District inspection demonstrates that a violation of the provisions of Sections 5.1, 5.2, or 5.3 exists for that component type; or

5.2.10.2 The APCO issued a Notice of Violation for violating any of the provisions of this rule during the annual inspection period for that component type.

5.2.11 Until June 30, 2024, ~~W~~when the inspection frequency changes from annual to quarterly inspections pursuant to Section 5.2.10, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency. The written notification shall include the reason(s) and date of change to quarterly inspection frequency.

5.2.12 The operator shall initially inspect a PRD that releases to the atmosphere using the test method specified in Section 6.3.1 as soon as practicable but not later than 24 hours after the time of the release. The operator shall re-inspect the PRD using the test method specified in Section 6.3.1 not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release to insure that the PRD is operating properly, and is leak-free. If the PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections.

5.2.13 Except for PRD subject to the requirements of Section 5.2.12, a component shall be inspected not later than 15 calendar days after repairing the leak or replacing the component using the test method specified in Section 6.3.1.

5.2.14 A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered a willful circumvention of the rule and is a violation of this rule.

5.2.15 After June 30, 2024, if a leaking component requires a rig-up operation to complete repair, an extended repair period may be granted for up to 30 calendar days from initial leak detection under the following conditions:

5.2.15.1 The operator shall notify the District within the compliant repair period. Notification shall include the following:

5.2.15.1.1 Well identification and physical location of the well being repaired.

5.2.15.1.2 The date and time the component was found to be leaking and the leak concentration.

5.5.15.1.3 Proof that equipment or other required services necessary to make the repairs have been ordered or scheduled.

5.2.15.2 The operator shall submit a written report within 7 calendar days of completing the repairs and re-inspecting the component using the test method in Section 6.3.1.

5.2.15.3 Operators who fail to comply with all of the requirements specified in Sections 5.2.15.1 and 5.2.15.2 shall be in violation with the provisions of this rule.

5.3 Maintenance Requirements:

5.3.1 Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag.

5.3.2 The tag shall remain affixed to the component until all the conditions specified in Sections 5.3.2.1 through 5.3.2.3 have been met.

5.3.2.1 The leaking component has been repaired or replaced; and

5.3.2.2 The component has been re-inspected using the test method in Section 6.3.1; and

5.3.2.3 The component is found to be in compliance with the requirements of this rule.

5.3.3 The tag shall include the following information:

5.3.3.1 Date and time of leak detection.

5.3.3.2 Date and time of leak measurement.

5.3.3.3 For gaseous leaks, indicate the leak concentration in ppmv.

5.3.3.4 For liquid leaks, indicate whether it is a major liquid leak or a minor liquid leak.

5.3.3.5 For essential components, unsafe-to-monitor components, or critical components, so indicate on the tag.

5.3.4 An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere.

5.3.5 If the leak has been minimized but the leak still exceeds the applicable leak standards of this rule, an operator shall comply with at least one of the requirement of Sections 5.3.5.3, 5.3.5.4 or 5.3.5.5 as soon as practicable but not later than the time period specified in Table ~~3~~5 until June 30, 2024 and Table 6 after June 30, 2024. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Table ~~3~~5 until June 30, 2024, and Table 6 after June 30, 2024, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required.

5.3.5.1 The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table ~~3~~5.

5.3.5.2 The start of the repair period shall be the time of the initial leak detection.

5.3.5.3 Repair or replace the leaking component; or

5.3.5.4 Vent the leaking component to a closed vent system as defined in Section 3.0.

5.3.5.5 Remove the leaking component from operation.

Table ~~3~~5 – Repair Period until June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 1)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	2	0
Liquid Leaks		
Minor Liquid Leak ~~(See Section 3.20.2)~~	3	0
Major Liquid Leak ~~(See Section 3.20.1)~~	2	0

Table 6 – Repair Period after June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak	7	0
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than or equal to 50,000 ppmv	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

5.3.6 If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall:

5.3.6.1 Minimize the leak within one hour after detection of leaks; and

5.3.6.2 If the leak has been minimized, but the leak still exceeds the applicable leak standards of this rule, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier.

5.3.7 For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the

requirements specified in Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6.

5.3.7.1 Replace or retrofit the component with the control technology specified in Table 47. Notify the APCO in writing prior to replacing or retrofitting the component; or

Table 47 – Component Control Technology Replacement/Retrofit

Component Type	Control Technology
Compressors	Replace existing seal with dual mechanical seal, oil-film seal, gas seal, or face-type seal
Pumps	Replace with seal-less pump or replace with dual mechanical seal
PRD	Replace PRD and install a rupture disc in the line which precedes the PRD such that the PRD is in series with and follows the rupture disc.
Valves	Replace with sealed bellows valve, or graphite or teflon chevron seal rings in a live-loaded packing gland
Threaded Connections	Weld connections or replace threaded connections with flanges
Sampling Connections	Replace with closed-loop sampling system

5.3.7.2 Replace the component with Achieved-in-Practice Best Available Control Technology (BACT) equipment, as determined in accordance with Rule 2201 (New and Modified Stationary Source Review Rule), and as approved by the APCO in writing; or

5.3.7.3 Vent the component to an APCO-approved closed-vent system as defined in Section 3.0; or

5.3.7.4 Remove the component from operation.

5.3.7.5 For any component that is accessible, is not unsafe-to-monitor, is not an essential component, is not a critical component, the operator shall comply with the requirement of Section 5.3.7.1, Section 5.3.7.2, Section 5.3.7.3, or Section 5.3.7.4 as soon as practicable but not later than twelve (12) months after the date of detection of the fifth major leak within a continuous 12-month period as indicated in Section 5.3.7.

5.3.7.6 For any inaccessible component, unsafe-to-monitor component, essential component, or critical component the operator shall comply with the requirement of Section 5.3.7.1, Section 5.3.7.2,

Section 5.3.7.3 or Section 5.3.7.4 as soon as practicable but not later than the next turnaround or not later than two (2) years after the date of detection of the fifth major leak within a continuous 12-month period as indicated in Section 5.3.7, whichever comes earlier.

5.4 Component Identification Requirements:

5.4.1 All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator or the APCO to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but not later than 24 hours after discovery.

5.4.2 The operator shall comply with the requirements of Section 6.1.4 if there is any change in the description of major components or critical components.

6.0 Administrative and Recordkeeping Requirements

6.1 Operator Management Plan

6.1.1 By October 20, 2005, an operator whose existing components are either subject to this rule or whose existing components are exempt pursuant to Section 4.2 of this rule on or before April 20, 2005 shall submit an Operator Management Plan for approval by the APCO.

6.1.2 The operator shall keep a copy of the APCO-approved Operator Management Plan at the facility and make it available to the APCO, ARB, and US EPA upon request.

6.1.3 The operator shall describe in the Operator Management Plan all components subject to this rule and all components that are exempt pursuant to Section 4.2 of this rule. The Plan shall contain a description of the procedures that the operator will use to comply with the requirements of this rule. The Plan shall include, at a minimum, all of the following information:

6.1.3.1 Identification and description of any known hazard that might affect the safety of an inspector.

6.1.3.2 Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following information:

6.1.3.2.1 Except for pipes, the number of components that are subject to this rule by component type and type of service (i.e., liquid service or gas/vapor service).

6.1.3.2.2 Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components that are subject to this rule including the reason(s) for such designation.

6.1.3.2.3 Except for pipes, the location of components subject to the rule (components may be grouped together functionally by process unit or facility description).

6.1.3.2.4 Except for pipes, components exempt pursuant to Section 4.2 (except for components buried below ground) may be described in the Operator Management Plan by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the applicable exemption criteria for components for which an exemption is being claimed pursuant to Sections 4.2 shall be submitted with the Operator Management Plan.

6.1.3.3 Detailed schedule of inspection to be conducted as required by this rule, including identification of all unmanned or manned oil production facilities, gas production facilities, and gas processing facilities.

6.1.3.4 Specify whether a qualified contractor or in-house team will perform the inspections.

6.1.3.5 Establish an employee training program for inspecting, repairing, and recordkeeping procedures, as necessary.

6.1.3.5.1 Specify the training standards for personnel performing inspections and repairs.

6.1.3.5.2 Document the leak detection training in conducting the test method specified in Section 6.3.1 for new operators, and for experienced operators, as necessary.

6.1.3.5.3 The operator shall maintain copies of the training records at the facility. Copies of the training records shall be

made available to the APCO, US EPA, and ARB upon request.

6.1.4 By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any or no changes to an existing Operator Management Plan.

6.1.5 The APCO shall provide written notice to the operator of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Plan. If the APCO fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of this rule.

6.2 Inspection Log

6.2.1 The operator shall maintain an inspection log containing, at a minimum, all of the following information:

6.2.1.1 Total number of components inspected, and total number and percentage of leaking components found by component types.

6.2.1.2 Location, type, name or description of each leaking component and description of any unit where the leaking component is found.

6.2.1.3 Date of leak detection and method of leak detection.

6.2.1.4 For gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record whether the leak is a major liquid leak or a minor liquid leak.

6.2.1.5 Date of repair, replacement, or removal from operation of leaking components.

6.2.1.6 Identification and location of essential components and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes earlier.

6.2.1.7 Methods used to minimize the leak from essential and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes earlier.

6.2.1.8 After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv.

6.2.1.9 Inspector's name, business mailing address, and business telephone number.

6.2.1.10 The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.

6.2.2 Records of leaks detected during quarterly or annual operator inspection, and each subsequent repair and re-inspection, shall be submitted to the APCO, ARB, and US EPA upon request.

6.2.3 Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.

6.2.4 Copies of all records required by Section 6.2 of this rule shall be retained for a minimum of five (5) years after the date of an entry, and the records shall be made available to the APCO, ARB, and US EPA upon request.

6.3 Test Methods

Equivalent test methods other than specified in Sections 6.3.1 through 6.3.8 may be used provided such test methods have received prior approval from the US EPA, ARB, and APCO.

6.3.1 Measurements of gaseous leak concentrations shall be conducted according to US EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in US EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument.

6.3.2 After June 30, 2024, all leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 6.

6.3.~~2~~3 The VOC content by weight percent (wt.%) shall be determined using American Society of Testing and Materials (ASTM) D1945-14 for gases and

South Coast Air Quality Management District (SCAQMD) Method 304-91 for liquids.

6.3.~~3~~4 The percent by volume liquid evaporated at 150°C shall be determined using ASTM Method D 86-82.

6.3.~~4~~5 The TVP of any organic liquid shall be determined by measuring the Reid Vapor Pressure (RVP) using ASTM D 323-94 (Test Method for Vapor Pressure for Petroleum Products), and converting the RVP to TVP at the maximum organic liquid storage temperature. The conversion of RVP to TVP shall be done in accordance with the procedures in Appendix A. Appendix A is an excerpt from the oil and gas section of "California Air Resources Boards (ARB) Technical Guidance Document to the Criteria and Guidelines Regulation for AB 2588", dated August 1989.

6.3.~~5~~6 The API gravity of crude oil or petroleum distillate shall be determined by using ASTM Method D 287-92 (2000) e1 "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method) or ASTM 1298-85 (Standard Practice for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method). Sampling for API gravity shall be performed in accordance with ASTM Method D 4057-95 "Standard Practices for Manual Sampling of Petroleum and Petroleum Products".

6.3.~~6~~7 The control efficiency of any VOC control device, measured and calculated as carbon, shall be determined by US EPA Method 25, except when the outlet concentration must be below 50 ppm in order to meet the standard, in which case US EPA Method 25a may be used. US EPA Method 18 may be used in lieu of US EPA Method 25 or US EPA Method 25a provided the identity and approximate concentrations of the analytes/compounds in the sample gas stream are known before analysis with the gas chromatograph and the gas chromatograph is calibrated for each of those known analyte/compound to ensure that the VOC concentrations are neither under- or over-reported.

6.3.~~7~~8 Halogenated exempt compounds shall be analyzed by US EPA Method 18 or ARB Method 422 "Determination of Volatile Organic Compounds in Emission from Stationary Sources".

7.0 Compliance Schedule

~~7.1 On and after April 20, 2006, the operator shall be in full compliance with the requirements of this rule, unless otherwise specified in the certain provisions of this rule.~~

~~7.2~~ ~~Operators may continue performing their quarterly inspection schedules that exist on or before April 20, 2005. Operators who are already on an annual inspection frequency on or before April 20, 2005 may apply for a written approval from the APCO to continue conducting annual inspections provided the operators meet all the criteria specified in Sections 5.2.9.~~

7.~~3~~1 Any component that is exempt pursuant to Section 4.2 that becomes subject to all the requirements of this rule through the loss of exemption status shall be in compliance with this rule on and after the date the exemption status is lost.

Appendix A

California Air Resources Board Technical Guidance
to the Criteria and Guidelines Regulation for AB 2588
(Partial Excerpt from pages 102, 103 and 104)

True Vapor Pressure (TVP)

RVP is the absolute pressure of volatile crude oil and nonviscous petroleum liquids. Numerically, the relationship between TVP, RVP and temperature can be expressed by the following equation:

$$TVP = (RVP)\, e^{[Co(IRTEMP - ITEMP)]}$$

Where: C_o = Constant dependent upon the value of RVP
ITEMP = $(1/559.69^oR)$
IRTEMP = $(1/(T_s + 459.69^oR))$
T_s = Temperature of the stored fluid in ^oF

The value of the constant term C_o depends upon the given value of RVP.

Values of C_o for different RVP numbers are tabulated in Table C-3. It should be noted, however, that an error was discovered in the API nomograph calculated values of TVP so that the RVP was not equal to TVP at 100°F as was expected given the general definition of RVP. Using linear regression techniques, correction factors (C_F) were developed and should be added to the calculated values of TVP in order to obtain reasonable TVP numbers. The relationship between the three values is given as follows:

$$\text{Corrected TVP} = \text{Calculated TVP} + C_F$$

The correction factor was found to be dependent upon RVP according to the following equations:

If RVP < 3,

$$C_F = (0.04) \times (RVP) + 0.1$$

If RVP > 3,

$$C_F = e^{[(2.3452061 \log (RVP)) - 4.132622]}$$

Appendix A (Continued)

Table C-3 VALUES OF C_o FOR DIFFERENT RVP NUMBERS

RVP	C_o
0<RVP<2	-6622.5
2<RVP<3	-6439.2
RVP = 3	-6255.9
3<RVP<4	-6212.1
RVP = 4	-6169.2
4<RVP<5	-6177.9
RVP = 5	-6186.5
5<RVP<6	-6220.4
RVP = 6	-6254.3
6<RVP<7	-6182.1
RVP = 7	-6109.8
7<RVP<8	-6238.9
RVP = 8	-6367.9
8<RVP<9	-6477.5
RVP = 9	-6587.9
9<RVP<10	-6910.5
RVP = 10	-7234.0
10<RVP<15	-8178.0
RVP > 15	-9123.2

RULE 4455 COMPONENTS AT PETROLEUM REFINERIES, GAS LIQUIDS PROCESSING FACILITIES, AND CHEMICAL PLANTS (Adopted April 20, 2005; Amended [*rule adoption date*])

1.0 Purpose

The purpose of this rule is to limit Volatile Organic Compound (VOC) emissions from leaking components at petroleum refineries, gas liquids processing facilities, and chemical plants.

2.0 Applicability

This rule shall apply to components containing or contacting VOC at petroleum refineries, gas liquids processing facilities, and chemical plants.

3.0. Definitions

3.1 APCO: The Air Pollution Control Officer of the San Joaquin Valley Unified Air Pollution Control District, or any person authorized to act on behalf of the APCO.

3.2 ARB: California Air Resources Board as established by the California Health and Safety Code Section 39510, or any person authorized to act on its behalf

3.3 Background: a reading on a portable hydrocarbon detection instrument which is determined at a distance no greater than two (2) meter upwind from any component to be inspected and which is uninfluenced by any specific emission point.

3.4 Chemical Plant: an establishment that produces organic chemicals and/or manufactures products by organic chemical processes.

3.5 Closed-vent System: an APCO-approved system that is not open to the atmosphere and that is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gas or vapor from a piece or pieces of equipment to an APCO-approved control device that has a overall VOC collection and destruction or removal efficiency of at least 95%, or that transports gases or vapors back to a process system.

3.6 Commercial Quality Natural Gas: a mixture of gaseous hydrocarbons with at least 80 percent methane by volume (≥ 80 vol%) and less than ten percent by weight (<10 wt%) VOC as determined by the test method specified in Section 6.4.2, and meets the criteria specified in Public Utilities Commission (PUC) General Order 58-A.

3.7 Component: includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, flange, process drain, sealing mechanism, hatch, sight-glass, meter or seal fluid system in VOC service.

3.7.1 Major Component: any pump 5 brake horsepower or larger, any compressor, and any pressure relief ~~valve~~ device 4 inches in diameter or larger.

~~3.7.2 Minor Component: any component that is not a major component.~~

3.8 Component Type: includes, but is not limited to, any one (1) of the following groups: valves, fittings, threaded connections, pumps, compressors, pressure relief devices, pipes, flanges, process drains, sealing mechanisms, hatches, sight-glasses, and meters in VOC service.

3.9 Compressor: a device used to compress gases or vapors or a combination of gases and vapors by the addition of energy, and includes all associated components used for connecting and sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the compressor. For example, a valve that is connected to a threaded hole on body of the compressor, the first VOC leak point is the threaded connection on the body of the compressor, but the valve itself is not a "first VOC leak point". Similarly, a compressor shaft seal is considered as a first “VOC leak point”.

3.10 Compressor Part: for the purpose of Section 5.3.7, a compressor part refers to the “first VOC leak point” as explained in Section 3.9.

3.11 Critical Component: any component that would require the shutdown of a critical process unit if that component was shut down or disabled.

3.12 Critical Process Unit: a process unit that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

3.13 Critical Process Unit Shutdown: the shutdown of a critical process unit or part of the critical process unit that causes the entire unit to cease operating.

3.14 District: San Joaquin Valley Unified Air Pollution Control District.

3.15 Essential Component: a component that cannot be taken out of service without reducing, by more than 33 percent, the throughput of the process unit that it serves.

3.16 Flange: a projecting rim on a pipe used to attach it to another pipe or any other component in a piping system.

3.17 Fitting: a component, excluding flanges and threaded connectors, used to attach or connect pipes or piping system. Examples of a "fitting" include, but are not limited to quick-disconnect fitting, push-in-fittings, and cam-locks.

3.18 Gas Liquids Processing Facility: a facility that is engaged in the catalytic processing of gas liquids to produce finished products.

3.19 Gas/Vapor Service: a component is considered to be in gas/vapor service when the fluid in contact with the component contains VOCs and the fluid is primarily in gaseous state at operating conditions.

3.20 Inaccessible Component: a component located over 15 feet above ground when access is required from the ground; or a component located over six (6) feet away from a platform when access is required from the platform; or a component that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.

3.21 Inspection: means checking and/or testing of components in order to detect leaks.

3.21.1 Operator Inspection: inspection of components conducted by the operator pursuant to the inspection and re-inspection schedules specified in this rule for the purpose of demonstrating compliance with this rule.

3.21.2 District Inspection: inspection of components by District personnel or their representative to insure facilities and/or operators are in compliance with District requirements.

3.22 Leak: the dripping of VOC-containing liquid or the detection of a concentration of total organic compound, above background, determined according to the test method specified in Section 6.4.1 that exceeds the limits in Table 1 or Table 2, Sections ~~s~~ 3.22.1 and Section 3.22.2 of this rule. Any liquid or gas coming from a component undergoing repair or replacement, or during sampling of process fluid from a component into a container is not considered a leak provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

Table 1 – Gas Leak Standard in ppmv as Methane until June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	200 to 10,000	400 to 10,000
2. Threaded connections	Greater than 10,000	200 to 10,000	400 to 10,000
3. Flanges	Greater than 10,000	200 to 10,000	400 to 10,000
3. Pumps	Greater than 10,000	500 to 10,000	1,000 to 10,000
4. Compressors	Greater than 10,000	500 to 10,000	1,000 to 10,000
5. PRD	Greater than 10,000	100 to 10,000	200 to 10,000
6. Other component types not listed in 1 through ~~6~~ 5 above	Greater than 10,000	500 to 10,000	1,000 to 10,000

Table 2 – Gas Leak Standard in ppmv as Methane after June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	200 to 10,000	400 to 10,000
2. Threaded connections	Greater than 10,000	200 to 10,000	400 to 10,000
3. Flanges	Greater than 10,000	200 to 10,000	400 to 10,000
3. Pumps	Greater than 10,000	500 to 10,000	500 to 10,000
4. Compressors	Greater than 10,000	500 to 10,000	500 to 10,000
5. PRD	Greater than 10,000	100 to 10,000	200 to 10,000
6. Other component types not listed in 1 through 5 above	Greater than 10,000	500 to 10,000	500 to 10,000

3.22.1 Major Liquid Leak: a visible mist or a continuous flow of liquid that is not seal lubricant.

3.22.2 Minor Liquid Leak: a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute.

3.23 Leak Minimization: reducing a leak to the lowest achievable level without damaging the component using best modern practices which include, but are not limited to, adding sealing material to the component, tightening the component, or adjusting the component without shutdown of the process that the component serves and that can be safely accommodated.

3.24 Liquid Service: a component is considered to be in liquid service when the fluid in contact with the component contains VOCs and the fluid is primarily liquid at operating conditions.

3.25 Open-ended Line or Valve: any line or valve, except for pressure relief devices ~~PRV~~ and process drains, having one side of the line or valve seat in contact with the process fluid and one side open to the atmosphere, either directly or through an open piping.

3.26 Optical Gas Imaging (OGI): an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

3.2~~6~~7 Portable Hydrocarbon Detection Instrument: a hand-held hydrocarbon analyzer that meets the criteria specified in US EPA Method 21, 40 CFR Part 60. The instrument shall be calibrated with methane.

3.2~~7~~8 Pressure Relief Device (PRD): a pressure relief valve, or a rupture disc, and an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere.

~~3.28 Pressure Relief Valve (PRV): an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere (atmospheric PRV).~~

3.29 Process Drain: any open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources. Drain origination points and drain termination points are not open-ended lines. Process drains are not open-ended lines.

3.30 Process Equipment: equipment that is used to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates.

3.31 Process Pressure Relief Device ~~PRD~~: a Pressure Relief Device (PRD) that is vented to the atmosphere and is located on a process equipment other than storage tanks, liquefied petroleum gas storage vessels, or pipelines used to transport materials.

3.32 Process System: an APCO-approved system that is not open to the atmosphere and is composed of hard-piping, ductwork connections and, if necessary, flow inducing devices that transport gases or vapors from a piece of equipment to a process stream, fuel gas system, or sales gas system.

3.33 Pump: a device used to transport fluids by the addition of energy, and includes all associated components used for connecting or sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the pump. For example, a valve that is connected to a threaded hole on body of the pump, the first VOC leak point is the threaded connection on the body of the pump, but the valve itself is not a "first VOC leak point". Similarly, a pump shaft seal is considered as a first “VOC leak point”.

3.34 Pump Part: for the purpose of Section 5.3.7, a pump part refers to the "first VOC leak point" as explained in Section 3.33.

3.35 Refinery: an establishment that processes petroleum as defined in the Standard Industrial Classification Code under 2911 (Petroleum Refining).

3.36 Release: a VOC emission to the atmosphere from process PRD caused by an increase in upstream pressure. A leak caused by improper reseating of the PRD is not a release.

3.37 Rupture Disk: a rigid diaphragm held between flanges for the purpose of isolating organic compounds from the atmosphere or from a downstream pressure relief ~~valve~~ device. Most rupture disks are designed to fail at a certain pressure point.

3.38 Tag: a piece of paper, metal, plastic or other suitable material that is attached to a component for the purpose identification or other information.

3.39 Turnaround: scheduled shutdown of a process unit for maintenance and repair work.

3.40 Sight glass: a device located on a fluid line or a process vessel that allows an operator to view the product or material inside a fluid line or a process vessel.

3.41 Unsafe-to-Monitor Component: a component that is installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.

3.42 US EPA: United States Environmental Protection Agency

3.43 Vacuum Service: operating under a negative gauge pressure or below atmospheric pressure.

3.44 Valve: a device that regulates the flow of fluid in a piping system by means of an external actuator acting to permit or block passage of fluid.

3.45 Volatile Organic Compound (VOC): as defined in Rule 1020 (Definitions).

4.0 Exemptions

4.1 The requirements of this rule shall not apply to components subject to Rule 4623 (Storage of Organic Liquids)~~; or to components included in the inspection and maintenance (I&M) program implemented pursuant to Section 5.7 of Rule 4623~~.

4.2 Except for complying with the applicable requirements of Sections 6.1 and 7.3, the requirements of this rule shall not apply to components described in Sections 4.2.1

through 4.2.8. An operator claiming an exemption pursuant to Section 4.2 shall provide proof of the applicable criteria to the satisfaction of the APCO.

4.2.1 Pressure relief devices, pumps, and compressors equipped with a closed-vent system as defined in Section 3.0.

4.2.2 Components buried below ground.

4.2.3 Components exclusively handling liquid streams which have less than 10 percent by weight (<10 wt%) evaporation at 150^0 C as determined by the test method specified in Section 6.4.3.

4.2.4 Components exclusively handling liquid streams with a VOC content less than ten percent by weight (<10 wt%), as determined by the test methods in Section 6.4.2.

4.2.5 Components exclusively handling gas/vapor streams with a VOC content of less than one percent by weight (<1wt%), as determined by the test method specified in Section 6.4.2.

4.2.6 Components incorporated in lines exclusively in vacuum service.

4.2.7 Components exclusively handling commercial natural gas.

~~4.2.8 One-half inch nominal or less stainless steel tube fittings which have been demonstrated to the APCO to be leak-free based on initial inspection using the test method specified in Section 6.4.1.~~

5.0 Requirements

5.1 Operating Requirements

5.1.1 The operator shall not use any component that leaks in excess of the applicable leak standards of this rule, or that is found to be in violation of the provisions specified in Section 5.1.3. Components that have been found leaking in excess of the applicable leak standards of this rule may be used provided such leaking components have been identified with a tag for repair, are repaired, or are awaiting re-inspection after being repaired, within the applicable time period specified in this rule.

5.1.2 Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

5.1.3 Determination of Compliance with the Leak Standards

5.1.3.1 District Inspection

The operator shall be in violation of this rule if any District inspection demonstrates that one or more of the conditions in Sections 5.1.4 exist at the facility.

5.1.3.2 Operator Inspection

5.1.3.2.1 Except for annual operator inspection described in Section 5.1.3.2.3, any operator inspection that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall not constitute a violation of this rule if the leaking components are repaired as soon as practicable but not later than the time frame specified in this rule. Such components shall not be counted towards determination of compliance with the provisions of Section 5.1.4.

5.1.3.2.2 Leaking components detected during operator inspection pursuant Section 5.1.3.2.1 that are not repaired, replaced, or removed from operation as soon as practicable but not later than the time frame specified in this rule shall be counted toward determination of compliance with the provisions of Section 5.1.4.

5.1.3.2.3 Any operator inspection conducted annually for a component type (including operator annual inspections pursuant to Section 5.2.5, 5.2.6, 5.2.7, or 5.2.8) that demonstrates one or more of the conditions in Section 5.1.4 exist at the facility shall constitute a violation of this rule regardless of whether or not the leaking components are repaired, replaced, or removed from operation within the allowable repair time frame specified in this rule.

5.1.4 Leak Standards

For the purpose of this rule, a component shall be considered ~~leaking~~ in violation if one or more of the conditions specified in Sections 5.1.4.1 through 5.1.4.4 exist at the facility.

5.1.4.1 An open-ended line or a valve located at the end of the line that is not sealed with a blind flange, plug, cap~~,~~; or a second closed valve

that is not closed at all times, except during attended operations requiring process fluid flow through the open-ended lines. Attended operations include draining or degassing operations, connection of temporary process equipment, sampling of process streams, emergency venting, and other normal operational needs, provided such operations are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

5.1.4.2 A component with a major liquid leak.

5.1.4.3 A component with a gas leak greater than 50,000 ppmv.

5.1.4.4 A component leak described in Sections 5.1.4.4.1 through 5.1.4.4.3 and numbering in excess of the maximum allowable number or percent specified in Table ~~2~~3.

5.1.4.4.1 A minor liquid leak; or

5.1.4.4.2 A minor gas leak; or

5.1.4.4.3 A gas leak greater than 10,000 ppmv up to 50,000 ppmv.

Table ~~2~~3 – Maximum Allowable Number or Percent of Leaking Components Per Inspection Period

Component Type	Maximum Number of Leaks for 200 or less Components Inspected	Maximum Percent or Number of Leaks for more than 200 Components Inspected*
1. Valves	1	0.5% of number inspected
2. Threaded Connections	1	0.5% of number inspected
3. Flanges	1	0.5% of number inspected
4. Pumps	2	1.0% of number inspected
5. Compressors	1	1 leak
6. PRD	1	1 leak
7. Other component types not listed in items 1 through 6 above	1	1 leak
8 Pipes	Maximum Number of Leaks	
	2	

*The maximum number of leaks in Table ~~2~~3 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components of a given type inspected during the specified inspection period. Leaks counted toward the allowable leaks in Table 3 are still subject to maintenance and repair requirements of Section 5.3.

5.2 Inspection and Re-Inspection Requirements

5.2.1 The operator shall audio-visually (by hearing and sight) inspect for leaks all accessible operating pumps, compressors, and PRDs in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours.

5.2.2 Any audio-visual inspection of all accessible operating pumps, compressors, and PRDs in service performed by an operator that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected using the test method specified in Section 6.4.1 not later than 24 hours after conducting the audio-visual inspection. If a leak is found, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table ~~3~~4 or Table 5 of this rule.

5.2.3 Notwithstanding the requirement of Sections 5.2.1 and 5.2.2, the operator shall inspect all components at least once every calendar quarter using the test method specified in Section 6.4.1, except for inaccessible components, unsafe-to-monitor components, or pipes. Inaccessible components and unsafe-to-monitor components shall be inspected in accordance with the provisions of Sections 5.2.5 and 5.2.6, respectively. Pipes shall be inspected in accordance with the provisions of Section 5.2.7.

5.2.4 The operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using the test method specified in Section 6.4.1.

5.2.5 The operator shall inspect all inaccessible components at least once every 12 months using the test method specified in Section 6.4.1.

5.2.6 The operator shall inspect all unsafe-to-monitor components during each turnaround using the test method specified in Section 6.4.1.

5.2.7 The operator shall visually inspect all pipes for leaks at least once every 12 months.

5.2.7.1 Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this rule shall be inspected using the test method specified in Section 6.4.1 not later than 24 hours after conducting the audio-visual inspection. If a leak is found, the leak shall be repaired as soon as practicable but not later than the timeframe specified in Table ~~3~~4 or Table 5 of this rule.

5.2.7.2 The operator may conduct the annual pipe inspection required by Section 5.2.7 in conjunction with the annual pipe inspection required by the Spill Prevention Control and Countermeasure Plan pursuant to 40 Code of Federal Regulation Part 112 (Oil Prevention and Response: Non-Transportation-Related Onshore and Offshore Facilities). Records of annual pipe inspection required by SPCC may be used to document the inspection required by Section 5.2.7. The operator shall maintain the records of such inspections at the facilities. The records shall be made available to the APCO, ARB, and US EPA upon request.

5.2.8 Until June 30, 2024, ~~N~~notwithstanding the requirement of Section 5.2.3, the operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, or an operator who is already on an annual inspection frequency on or before (rule adoption date) may apply for a written approval from the APCO to continue conducting annual inspections for a component type, provided the operator meets all the criteria specified in Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis.

5.2.8.1 The operator was not in violation of any provision of Sections 5.1 during five consecutive quarterly inspections for that component type.

5.2.8.2 The operator did not receive a Notice of Violation from the APCO during the previous 12 months for violating any provisions of this rule for that component type.

5.2.8.3 The written request shall include pertinent documentation to demonstrate that the operator has successfully met the requirements of Sections 5.2.8.1 and 5.2.8.2.

5.2.9 Until June 30, 2024, ~~T~~the annual inspection frequency approved by the APCO pursuant to Section 5.2.8 shall revert to quarterly inspection frequency for a component type if either one of the following occurs:

5.2.9.1 Operator inspection or District inspection demonstrates that a violation of the provisions of Sections 5.1, 5.2, and 5.3 exists for that component type, or

5.2.9.2 The APCO issued a Notice of Violation for violating any of the provisions of this rule during the annual inspection period for that component type.

5.2.10 Until June 30, 2024, ~~W~~when the inspection frequency changes from annual to quarterly inspections pursuant to Section 5.2.9 above, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency. The written notification shall include the reason(s) and date of change to quarterly inspection frequency.

5.2.11 The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. The operator shall re-inspect the process PRD using the test method specified in Section 6.4.1 not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release to insure that the process PRD is operating properly, and is leak-free. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections.

5.2.12 Except for process PRD subject to the requirements of Section 5.2.11, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using the test method specified in Section 6.4.1.

5.2.13 A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered a willful circumvention of the rule and is a violation of this rule.

5.3 Maintenance Requirements

5.3.1 Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag.

5.3.2 The tag shall remain affixed to the component until all the conditions specified in Sections 5.3.2.1 through 5.3.2.3 have been met.

5.3.2.1 The leaking component has been repaired or replaced; and

5.3.2.2 The component has been re-inspected using the test method in Section 6.4.1; and

5.3.2.3 The component is found to be in compliance with the requirements of this rule.

5.3.3 The tag shall include the following information:

5.3.3.1 Date and time of leak detection.

5.3.3.2 Date and time of leak measurement.

5.3.3.3 For gas leaks, indicate the leak concentration in ppmv.

5.3.3.4 For liquid leaks, indicate whether it is a major liquid leak or a minor liquid leak.

5.3.3.5 For essential components, unsafe–to-monitor components, or critical components, so indicate on the tag.

5.3.4 An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere.

5.3.5 If the leak has been minimized but the leak still exceeds the applicable leak standards of this rule, an operator shall comply with at least one of the requirement of Sections 5.3.5.3, 5.3.5.4, or 5.3.5.5 as soon as practicable but not later than the time period specified in Table ~~3~~4 or Table 5. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Table ~~3~~4 or Table 5, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required.

5.3.5.1 The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table ~~3~~4 or Table 5.

5.3.5.2 The start of the repair period shall be the time of the initial leak detection.

5.3.5.3 Repair or replace the leaking component; or

5.3.5.4 Vent the leaking component to a closed vent system as defined in Section 3.0.

5.3.5.5 Remove the leaking component from operation.

Table ~~3~~4 – Repair Period Until June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 1)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	2	0
Liquid Leaks		
Minor Liquid Leak (See Section 3.22.2)	3	0
Major Liquid Leak (See Section 3.22.1)	2	0

Table 5 – Repair Period After June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 2)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

5.3.6 If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall:

5.3.6.1 Minimize the leak within one hour after detection of leaks; and

5.3.6.2 If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of this rule, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier.

5.3.7 For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply

with at least one of the requirements specified in Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6.

5.3.7.1 Replace or retrofit the component with the control technology specified in Table 46. Notify the APCO in writing prior to replacing or retrofitting the component; or

Table 46 – Component Control Technology Replacement/Retrofit

Component Type	Control Technology
Compressors	Replace existing seal with dual mechanical seal, oil-film seal, gas seal, or face-type seal.
Pumps	Replace with seal-less pump or replace with dual mechanical seal.
PRD	Replace PRD and install a rupture disc in the line which precedes the PRD such that the PRD is in series with and follow the rupture disc.
Valves	Replace with sealed bellows valve, or graphite or teflon chevron seal rings in a live-loaded packing gland.
Threaded Connections	Weld connections or replace threaded connections with flanges.
Sampling Connections	Replace with closed-loop sampling system

5.3.7.2 Replace the component with Achieved-in-Practice Best Available Control Technology (BACT) equipment, as determined in accordance with Rule 2201 (New and Modified Stationary Source Review Rule), and as approved by the APCO in writing; or

5.3.7.3 Vent the component to an APCO approved closed vent system as defined in Section 3.0; or

5.3.7.4 Remove the component from operation.

5.3.7.5 For any component that is accessible, is not unsafe-to-monitor, is not an essential component, is not a critical component, the operator shall comply with the requirement of Section 5.3.7.1, Section 5.3.7.2, Section 5.3.7.3, or Section 5.3.7.4 as soon as practicable but not later than twelve (12) months after the date of detection of the fifth major leak within a continuous 12-month period as indicated in Section 5.3.7.

5.3.7.6 For any inaccessible component, unsafe-to-monitor component, essential component, or critical component, the operator shall comply with the requirement of Section 5.3.7.1, Section 5.3.7.2, Section 5.3.7.3, or Section 5.3.7.4 as soon as practicable but not later than the next turnaround or not later than two (2) years after the date of detection of the fifth major leak within a continuous 12-month period as indicated in Section 5.3.7, whichever comes earlier.

5.4 Process PRD Requirements

5.4.1 The operator shall monitor process PRD by using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process PRD where parameter monitoring is not feasible.

5.4.2 By October 20, 2005, the operator shall submit to the APCO a compliance plan, as part of the Operator Management Plan required by Section 6.1, containing the inventory of process PRD by size, set pressure and location, and the type of monitoring system to be used in order to comply with the requirement of Section 5.4.1. If applicable, the operator shall indicate the process parameter selected for continuous monitoring and the justification for such selection.

5.4.3 The operator shall comply with the process PRD release notification and recordkeeping requirements specified in Section 6.3.

5.4.4 After a release from process PRD in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable but not later than 30 days to prevent the reoccurrence of similar release. For refineries processing greater than 20,000 barrels of crude oil per day, any subsequent release in excess of 500 pounds of VOC within a continuous 24-hour period shall be subject to the requirements of Section 5.4.5.

5.4.5 The operator of a refinery processing greater than 20,000 barrels of crude oil per day shall connect all process PRD serving that process equipment to an APCO-approved closed vent system as defined in Section 3.0 if any of the conditions specified in Sections 5.4.5.1 and 5.4.5.2 occurs. Process PRD subject to the provisions of Section 5.4.5 shall be connected to an APCO-approved closed vent system as soon as practicable, but no later than the first turnaround after the requirement to connect becomes effective.

5.4.5.1 A second release from any process PRD serving the same piece or pieces of equipment and each release is in excess of 500 pounds

of VOC in a continuous 24-hour period and provided the second release occurs within any five year period of the first release.

5.4.5.2 Any release in excess of 2,000 pounds of VOC in a continuous 24-hour period, from any process PRD serving the same piece or pieces of process equipment.

5.5 Component Identification Requirements

5.5.1 All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator or District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but not later than 24 hours after discovery.

5.5.2 The operator shall comply with the requirements of Sections 6.1.4 if there is any change in the description of major components or critical components.

6.0 Administrative and Recordkeeping Requirements

6.1 Operator Management Plan

6.1.1 By October 20, 2005, an operator whose existing components are either subject to the rule or whose existing components are exempt pursuant to Section 4.2 on or before April 20, 2005 shall submit an Operator Management Plan for approval by the APCO.

6.1.2 The operator shall keep a copy of the APCO-approved Operator Management Plan at the facility and make it available to the APCO, ARB and US EPA upon request.

6.1.3 The operator shall describe in the Operator Management Plan all components subject to this rule and all components that are exempt pursuant to Section 4.0 of this rule or part of this rule. The Plan shall contain a description of the procedures that the operator will use to comply with the requirements of this rule. The Plan shall include, at a minimum all of the following information:

6.1.3.1 Identification and description of any known hazard that might affect the safety of an inspector.

6.1.3.2 Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following information:

6.1.3.2.1 Except for pipes, the number of components that are subject to this rule by component type and type of service (i.e., liquid service or gas/vapor service).

6.1.3.2.2 Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components, that are subject to this rule, including the reason(s) for such designation.

6.1.3.2.3 Except for pipes, the location of components that are subject to this rule (components may be grouped together functionally by process unit or facility description).

6.1.3.2.4 Except for pipes components exempt pursuant to Section 4.2 (except for components buried below ground) may be described in the Operator Management Plan by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the exemption criteria for components for which an exemption is being claimed pursuant to Sections 4.2 shall be submitted with the Operator Management Plan.

6.1.3.4 Detailed schedule of inspection to be conducted as required by this rule.

6.1.3.5 Include the compliance plan for process PRD as required by Section 5.4.2 of this rule.

6.1.3.6 Specify whether a qualified contractor or in-house team will perform the inspections.

6.1.3.7 Establish an employee training program for inspecting, repairing, and recordkeeping procedures, as necessary.

6.1.3.7.1 Specify the training standards for personnel performing inspections and repairs.

6.1.3.7.2 Document the leak detection training using the test method in Section 6.4.1 for new operators, and for experienced operators, as necessary.

6.1.3.7.3 The operator shall maintain copies of the training records at the facility. Copies of the training records shall be made available to the APCO, ARB, and US EPA upon request.

6.1.4 By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any or no changes to an existing Operator Management Plan.

6.1.5 The APCO shall provide written notice to the operator of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Plan. If the APCO fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of this rule.

6.2 Inspection Log

6.2.1 An operator at each facility shall maintain an inspection log containing, at a minimum, the following information:

6.2.1.1 Total number of components inspected, and total number and percentage of leaking components found by component types.

6.2.1.2 Location, type, name or description of each leaking component, and description of any unit where the leaking component is found.

6.2.1.3 Date of leak detection and method of leak detection.

6.2.1.4 For gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record whether the leak is a major liquid leak or a minor liquid leak.

6.2.1.5 Date of repair, replacement, or removal from operation of leaking components.

6.2.1.6 Identification and location of essential component and critical components found leaking that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier.

6.2.1.7 Methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later one year after leak detection, whichever comes earlier.

6.2.1.8 After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv.

6.2.1.9 Inspector's name, business mailing address, and business telephone number.

6.2.1.10 The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.

6.2.2 Until June 30, 2024, ~~R~~records of leaks detected by quarterly or annual operator inspection, and each subsequent repair and re-inspection, shall be submitted to the APCO, ARB, or US EPA upon request.

6.2.3 After June 30, 2024, records of leaks detected by operator inspection, and each subsequent repair and re-inspection, shall be submitted to the APCO, ARB, and US EPA upon request.

6.2.~~3~~4 Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.

6.2.4 Copies of all records required by Section 6.2 of this rule shall be retained for a minimum of five (5) years after the date of an entry. Such records shall be made available to the APCO, ARB, ~~or~~ and US EPA upon request.

6.3 Process PRD Release Notification

6.3.1 The operator shall notify the APCO, by telephone or other methods approved by the APCO, of any process PRD release described in Sections 5.4.4 and 5.4.5, and any release in excess of the reportable quantity limits as stipulated in 40 CFR, Part 117, Part 302 and Part 355, including any release in excess of 100 pounds of VOC, within one hour of such occurrence or within one hour of the time said person knew or reasonably should have known of its occurrence.

6.3.2 The operator shall submit a written report to the APCO within thirty (30) calendar days of following notification of process PRD release subject to 6.3.1. The written report shall include all of the following information:

6.3.2.1 Process PRD type, size, and location.

6.3.2.2 Date, time and duration of the process PRD release.

6.3.2.3 Types of VOC released and individual amounts, in pounds, including supporting calculations.

6.3.2.4 Cause of the process PRD release.

6.3.2.5 Corrective actions taken to prevent a subsequent process PRD release.

6.3.3 The operator shall keep records of the process (s) parameters monitored pursuant to Section 5.4.1 for a period of five (5) years, and make the records available to the APCO, ARB, and US EPA upon request.

6.4 Test Methods

Equivalent test methods other than specified in Sections 6.4.1 through 6.4.5 may be used provided such test methods have received prior approval from the US EPA, ARB, and APCO.

6.4.1 Measurements of gaseous leak concentrations shall be conducted according to US EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in US EPA Method 21 or the manufacturer's instruction, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument.

6.4.1.1 After June 30, 2024, All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 5.

6.4.2 The VOC content shall be determined using American Society of Testing and Materials (ASTM) D 1945-14 for gases and South Coast Air Quality Management District (SCAQMD) Method 304-91 for liquids.

6.4.3 The percent by volume liquid evaporated at 150^0C shall be determined using ASTM D 86-82.

6.4.4 The control efficiency of any VOC control device, measured and calculated as carbon, shall be determined by US EPA Method 25, except when the outlet concentration must be below 50 ppm in order to meet the standard, in which case Method 25a may be used. US EPA Method 18 may be used in lieu of US EPA Method 25 or US EPA Method 25a provided the identity and approximate concentrations of the analytes/compounds in the sample

gas stream are known before analysis with the gas chromatograph and the gas chromatograph is calibrated for each of those known analyte/compound to ensure that the VOC concentrations are neither under- or over-reported.

6.4.5 Halogenated exempt compounds shall be analyzed by US EPA Method 18 or ARB Method 422 "Determination of Volatile Organic Compounds in Emission from Stationary Sources".

7.0 Compliance Schedule

~~7.1 On and after April 20, 2006, the operator shall be in full compliance with the requirements of this rule, unless otherwise specified in certain provisions of this rule.~~

7.~~2~~1 Until June 30, 2024, ~~O~~operators may continue performing their quarterly inspection schedules that exist on or before April 20, 2005. Operators who are already on an annual inspection frequency on or before April 20, 2005, may apply for a written approval from the APCO to continue conducting annual inspections provided the operators meet all the criteria specified in Sections 5.2.8.

7.~~3~~2 Any component that is exempt pursuant to Section 4.2 that becomes subject to all the requirements of this rule through the loss of exemption status shall be in compliance with this rule on and after the date the exemption status is lost.

RULE 4623 STORAGE OF ORGANIC LIQUIDS (Adopted April 11, 1991; Amended September 19, 1991; Amended December 17, 1992; Amended December 20, 2001; Amended May 19, 2005; Amended [*rule adoption date*])

1.0 Purpose

The purpose of this rule is to limit ~~v~~Volatile ~~o~~Organic ~~c~~Compound (VOC) emissions from the storage of organic liquids.

2.0 Applicability

This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held, or stored, and any tank used in crude oil or natural gas production operations with a potential to emit six (6) tons of VOC or greater per year.

3.0 Definitions

3.1 APCO-approved VOC Control System: either an external floating-roof tank complying with Section 5.3 provisions, internal floating-roof tank complying with Section 5.4 provisions, a vapor recovery system complying with Section 5.6 provisions, or pressure vessel as defined in Section 3.~~2~~4~~3~~2.

3.2 Capacity: the volume of a tank, as shown in the Permit to Operate (PTO), or the tank manufacturer's specifications if a tank does not have a PTO, or as determined by District measurements.

3.3 Clean Produced Water: as defined in Rule 1020 (Definitions).

3.4 Component: includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure-vacuum relief valve, pressure relief device, pipe, flange, process drain, sealing mechanism, hatch, sight-glass, meter, or seal fluid system in VOC service. This definition includes tanks and separators.

3.5 Compressor: a device used to compress gases or vapors or a combination of gases and vapors by the addition of energy, and includes all associated components used for connecting and sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) connected on the body of the compressor. For example, a valve that is connected to a threaded hole on body of the compressor, the first VOC leak point is the threaded connection on the body side of the compressor, but the valve itself is not a "first VOC leak point". Similarly, a compressor shaft seal is considered as a first "VOC leak point".

3.6 Compressor Part: for the purpose of Section 5.9.4.9, a compressor part refers to the "first VOC leak point" as explained in Section 3.5.

3.47 Contact Floating Roof: a roof, located inside an internal floating roof tank, that floats on the liquid surface.

3.58 Crude Oil: petroleum extracted from the earth and which has not been processed in a refining operation.

3.69 Deck Fitting: a functional or operational device on a tank floating roof that substantially closes or seals a penetration in the deck of a floating roof.

3.710 Degassing: the process of removing organic vapors from a storage tank.

3.811 Emergency Standby Tank: a tank that does not receive or store an organic liquid for more than 60 cumulative days during any 12-month period.

3.912 External Floating Roof: a tank cover in an open top tank consisting of a pan type, pontoon type, or double-deck type cover that rests upon and is supported by the organic liquid being contained. An external floating roof is equipped with closure seals to close the space between the roof edge and tank shell.

3.103 Fixed Roof Tank: a tank with a roof that is permanently affixed to the shell of the tank.

3.114 Gas Leak: a reading in excess of ~~10,000~~ the values specified in Table 1 or Table 2 as parts per million by volume (ppmv), as methane, above background on a portable hydrocarbon detection instrument that is calibrated with methane in accordance with the test method in Section 6.4.8.

Table 1 Gas Leak (Until June 30, 2024)	
	Gas Leak
Components	Greater than 10,000

Table 2 Gas Leak (After June 30, 2024)		
	Minor Gas Leak	Major Gas Leak
Components	500 to 10,000	Greater than 10,000

3.125 Gasoline: any petroleum distillate, petroleum distillate/alcohol blend, or alcohol, having a Reid vapor pressure of four (4) psia or greater which is used as motor fuel which is commonly or commercially known or sold as gasoline.

3.136 Gauge Float: a device to indicate the level of the liquid within a tank. The float rests on the liquid surface inside a gauge well in the tank.

3.147 Gauge Hatch/Sample Well (Ports): consists of a pipe sleeve equipped with a self-closing gasketed cover (to reduce evaporative losses) and allows hand-gauging or sampling of the stored liquid. The gauge hatch/sample port is usually located

beneath the gauger's platform, which is mounted on top of the tank shell. A cord may be attached to the self-closing gasketed cover so that the cover can be opened from the platform.

3.1~~5~~8 Guidepole: an anti-rotation device that is fixed to the top and bottom of a tank, passing through a well in a floating roof. A guidepole may be solid or be equipped with slots or holes for gauging purposes provided the guidepole is equipped with an appropriate sealing device that prevents openings that expose the stored liquid to the atmosphere.

3.19 Inaccessible Component: a component that is located over 15 feet above ground when access is required from the ground; or a component that is located over six (6) feet away from a platform when access is required from the platform, or a component in a location that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.

3.~~16~~20 Internal Floating Roof: a pan type, pontoon type, or double-deck type cover located inside a fixed roof tank that rests upon and is supported by the organic liquid being contained. An internal floating roof is equipped with closure seals to close the space between the roof edge and tank shell.

3.~~17~~21 Leak-Free: a condition without a gas leak or a liquid leak.

3.22 Leak Minimization: reducing a leak to the lowest achievable level without damaging the component using best modern practices which include, but are not limited to, adding sealing material to the component, tightening the component, or adjusting the component without shutdown of the process that the component serves and that can be safely accommodated.

3.~~18~~23 Liquid Leak: the dripping of organic liquid at a rate of more than 3 drops per minute.

3.~~19~~24 Maximum Operating Level: the highest achievable level of fluid within a tank, as determined by the structural design of the tank. In the absence of tank specific design information, the maximum operating level is equal to tank capacity.

3.2~~0~~5 Metallic-Shoe Type (Mechanical Shoe) Seal: a metallic sheet (the shoe) that is held vertically against the vertical tank wall. The shoe is connected by braces to the floating roof and is held tightly against the wall by springs or weighted levers. A flexible coated fabric (envelope) is suspended from the shoe seal to the floating roof to form a vapor barrier over the annular space between the roof and the primary seal.

3.2~~1~~6 Non-contact Floating Roof: a roof that is located inside an internal floating roof tank that is supported on pontoons several inches above the liquid surface.

3.2~~2~~7 Organic Liquid: any liquid which contains volatile organic compounds (VOCs) including, but not limited to, crude oils and petroleum distillates.

3.28 Optical Gas Imaging (OGI): an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

3.2~~3~~9 Petroleum Distillate: the product of a crude oil distillation or condensation process obtained by condensing the vapors for the purpose of purification, fractionation, or the formation of new substances.

3.30 Process Drain: any open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources.

3.~~24~~31 Pressure Vessel: a tank, reservoir, or container that is capable of maintaining working pressures sufficient to prevent organic liquid loss or VOC loss to the atmosphere at all times.

3.32 Pressure Relief Device (PRD): a pressure relief valve, a rupture disk, or an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere.

3.33 Pump: a device used to transport fluids by the addition of energy, and includes all associated components used for connecting or sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the pump. For example, a valve that is connected to a threaded hole on body of the pump, the first VOC leak point is the threaded connection on the body side of the pump, but the valve itself is not a "first VOC leak point." Similarly, a pump shaft seal is considered as a first "VOC leak point."

3.34 Pump Part: for the purpose of Section 5.9.4.9, a pump part refers to the "first VOC leak point" as explained in Section 3.33.

3.~~25~~35 Resilient-Toroid-Type seal: a core of open-cell foam encapsulated in a coated fabric that is attached to a mounting on the deck perimeter~~,~~ and is continuous around the floating roof circumference.

3.~~26~~36 Rim Vent: a vent used on tanks equipped with a seal design, such as a mechanical shoe seal, that creates a vapor pocket in the seal and rim area. The vent is used to release excess pressure or vacuum that is present in the vapor space bounded by the primary-seal shoe, the floating roof rim, the primary seal fabric, and the liquid level. A rim vent usually consists of a weighted pallet that rests on a gasketed cover.

3.~~27~~37 Roof Drain: a drain that permits the removal of rainwater from the surface of external floating roofs. A roof drain may be a closed drainage system that carries rainwater from the surface of the floating roof to the outside of the tank, or an open drainage system consisting of an open pipe that extends a short distance below the bottom of the deck allowing rainwater to drain from the surface of the floating roof into the organic liquid contents of the tank.

3.~~28~~38 Roof Leg: an adjustable or fixed leg that is attached to the floating roof deck to support or hold the floating roof deck at a predetermined distance off the tank bottom to prevent damage to the fittings located underneath the deck and to allow for tank cleaning or repair. For adjustable legs, the load-carrying element passes through a well or sleeve in the deck.

3.~~29~~39 Small Producer: an operator in the business of crude oil production who:

3.~~29~~39.1 Produces an average of less than 6000 barrels per day of crude oil from all operations within the county; and

3.~~29~~39.2 Does not engage in refining, transportation, or marketing of refined petroleum products.

3.~~30~~40 Tank: any stationary container, reservoir, or vessel, in which an organic liquid is placed, held, or stored. This definition includes components connected to the body of the tank. For example, a valve that is connected to a threaded hole on the body of the tank, the first VOC leak point is the threaded connection on the body side of the tank, but the valve itself is a separate component from the tank.

3.~~31~~41 Tank Battery: for crude oil production facilities, a tank battery is an aggregation of two or more tanks where the tanks are located so that no one tank is more than 150 feet from another tank as measured from the closest tank edges, and the tanks are located in the same crude oil production field. For non-crude oil production facilities, a tank battery is an aggregation of two or more tanks located within the same facility, regardless of the distance of the tanks from each other.

3.~~32~~42 True Vapor Pressure (TVP): the equilibrium partial vapor pressure exerted by an organic liquid at actual storage temperature.

3.~~33~~43 Uncontrolled Fixed Roof Tank: a fixed roof tank that is not connected to an APCO-approved vapor recovery system operated as specified in Section 5.6.

3.44 Unsafe-to-Monitor Component: a component installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.

3.~~34~~45 Vacuum Breaker: a device that equalizes the pressure of the vapor space across the floating roof deck as the deck is either being landed on or off its legs. A vacuum breaker consists of a well with a cover. Attached to the underside of the cover is a

guided leg long enough to contact the tank bottom as the floating deck approaches. When in contact with the tank bottom, the guide leg mechanically opens the breaker by lifting the cover off the well; otherwise the cover closes the well. Because the purpose of the vacuum breaker is to allow for the free exchange of air and/or vapor, the well does not extend appreciably below the deck.

3.~~35~~46 Visible Gap: an opening that exceeds 0.060 inch.

3.~~36~~47 Volatile Organic Compound (VOC): as defined in Rule 1020 (Definitions).

3.~~37~~48 Zero Gap: no gap between the tank shell and the seal shall exceed 0.06 inch. The cumulative length of all gaps exceeding 0.02 inch shall not be more than five (5) percent of the circumference of the tank, excluding gaps less than 1.79 inches from vertical seams.

3.~~38~~49 Zero Gap Pole Wiper Seal: a seal with no gap exceeding 0.06 inches between outer surface of the guidepole or gauge well and pole wiper seal.

4.0 Exemptions

4.1 The provisions of this rule shall not apply to:

4.1.1 Pressure vessels.

4.1.2 Gasoline storage tanks with a capacity of less than 19,800 gallons that are subject to the requirements of Rule 4621 (Gasoline Transfer Into Stationary Storage Containers, Delivery Vessels, and Bulk Plants).

4.1.3 Tanks that are used for storage/processing of clean produced water, or other water that meets the VOC standard specified in the definition of "clean produced water" in Rule 1020 (Definitions) unless the tank has a potential to emit six (6) tons of VOC emissions or greater per year and is used in crude oil and natural gas production operations.

4.1.4 Tanks used in wine fermentation and for storage of resulting products, by-products, and spirits.

4.2 Except for complying with Sections 6.3.2, 6.3.3, and 7.~~2~~1, the requirements of this rule shall not apply to:

4.2.1 Emergency standby tanks, in existence prior to May 1, 1979, which exclusively store petroleum distillates or crude oil. Prior to return to Emergency Standby status, the contents of each tank shall be drained to the maximum extent feasible. After a tank has been used (filled or partially filled) and draining of the tank has begun, any further filling of the tank shall constitute a separate use of the tank, and the number of days the tank is used

shall be counted towards the 60 cumulative days limit specified in the definition of an emergency standby tank in Section 3.~~8~~11. Fixed roof emergency standby tanks shall be equipped with a pressure-vacuum relief valve that meets the requirements of Section 5.2.

4.2.2 Temporary tanks, with capacities of 21,000 gallons (500 barrels) or less, left on site for six months or less.

4.3 Except for complying with Sections 6.3.4 and 7.~~2~~1, a small producer's tank with a throughput of 50 barrels of crude oil per day or less is exempt from the requirements of this rule. All other small producer tanks that do not qualify for exemption under Section 4.4 shall comply with all the requirements of this rule.

4.4 Until June 30 2024, ~~T~~tanks exclusively receiving and/or storing an organic liquid with a TVP less than 0.5 psia are exempt from all other requirements of the rule except for complying with the following provisions:

After June 30, 2024, tanks exclusively receiving and/or storing an organic liquid with a TVP less than 0.1 psia are exempt from all other requirements of the rule except for complying with the following provisions:

4.4.1 TVP and API Gravity Testing provisions pursuant to Section 6.2,

4.4.2 Recordkeeping provisions pursuant to Section 6.3.6,

4.4.3 Test Methods provisions pursuant to Section 6.4, and

4.4.4 Compliance schedules pursuant to Section 7.~~2~~0.

4.4.5 After June 30, 2024, operators shall follow the storage tank degassing and interior cleaning requirements pursuant to Section 5.7.5 for notification, recordkeeping, tank degassing, tank cleaning, and sludge removal.

The requirements of Section 4.4 shall not apply to tanks that are exempt pursuant to Sections 4.1 through 4.3.

5.0 Requirements

5.1 VOC Control System Requirements

5.1.1 General VOC Control System Requirements

Except for small producers who are required to comply with the VOC control system requirements in Section 5.1.2, an operator shall not place, hold, or store organic liquid in any tank unless such tank is equipped with a VOC

control system identified in Table ~~1~~3 or Table 4. The specifications for the VOC control system are described in Sections 5.2, 5.3, 5.4, 5.5, and 5.6.

Table ~~1~~3 – General VOC Control System Requirements until June 30, 2024

Tank Capacity (Gallons)	True Vapor Pressure (TVP) of Organic Liquid		
	0.5 psia to <1.5 psia	1.5 psia to <11 psia	≥11.0 psia
(Group A) 1,100 to 19,800	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group B) >19,800 to 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group C) >39,600	Internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system

Table 4 – General VOC Control System Requirements after June 30, 2024

Tank Capacity (Gallons)	True Vapor Pressure (TVP) of Organic Liquid			
	0.1 psia to <0.5 psia	0.5 psia to <1.5 psia	1.5 psia to <11 psia	≥11.0 psia
(Group A) 1,100 to 19,800	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group B) >19,800 to 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group C) >39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system

5.1.1.1 If a tank has the Potential to Emit greater than or equal to six (6) tons per year of VOC and actual emissions are greater than or equal to four (4) tons per year using a generally accepted model or calculation methodology, operator must install a vapor control system meeting the specifications described in Sections 5.3, 5.4, 5.5 or 5.6.

5.1.2 Small Producer VOC Control System Requirements

A small producer shall not place, hold, or store crude oil in any tank unless such tank is equipped with a VOC control system identified in Table ~~2~~5 or Table 6. For storage of any organic liquid except crude oil, a small producer shall comply with the requirements of Section 5.1.1. The specifications for the VOC control system are described in Sections 5.2, 5.3, 5.4, 5.5, and 5.6.

Table ~~2~~5 – Small Producer VOC Control System Requirements for Crude Oil Storage Tanks until June 30, 2024

Tank Capacity (gallons)	TVP and Crude Oil Throughput		
	0.5 psia to <11 psia and a tank throughput of >50 to <150 barrels of crude oil per day	0.5 psia to <11 psia and a tank throughput ≥150 barrels of crude oil per day	≥11 psia and regardless of crude oil tank throughput
(Group A) 1,100 to 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group B) >39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system

Table 6 – Small Producer VOC Control System Requirements for Crude Oil Storage Tanks after June, 30, 2024

Tank Capacity (gallons)	TVP and Crude Oil Throughput			
	0.1 psia to <11 psia and a tank throughput of >50 to <150 barrels of crude oil per day	0.1 psia to <0.5psia and a tank throughput ≥150 barrels of crude oil per day	0.5 psia to <11 psia and a tank throughput ≥150 barrels of crude oil per day	≥11 psia and regardless of crude oil tank throughput
(Group A) 1,100 to 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group B) ≥39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system

5.1.2.1 If tank VOC emissions have the Potential to Emit greater than or equal to six (6) tons per year of VOC and actual emissions are greater than or equal to four (4) tons per year using a generally accepted model or calculation methodology, install a vapor control system meeting the specifications described in Sections 5.3, 5.4, 5.5 or 5.6.

5.1.3 All tanks subject to the control requirements of this rule shall be maintained in a leak-free condition, except for the following components and as allowed by Section 5.2 and applicable provisions of Table ~~3~~5 through Table ~~5~~7, and Section 5.7.5.4:

5.1.3.1 Primary seals and secondary seals of external floating roof tanks that are in compliance with the applicable requirements specified in Sections 5.3.2.1, 5.3.2.2, and 5.3.2.3.

5.1.3.2 Primary seals and secondary seals of internal floating roof tanks that are in compliance with the applicable requirements specified in Section 5.4.1.

5.1.3.3 Floating roof deck fittings that are in compliance with the applicable requirements specified in Sections 5.5.2.1.5, 5.5.2.2.5, 5.5.2.3.3, 5.5.2.4.2, and 5.5.2.4.3.

5.1.3.4 Floating roof automatic bleeder vents that are in compliance with requirements specified in Sections 5.5.2.1.3 and 5.5.2.2.3 during product change provided product change is accomplished as expeditiously as practicable.

5.2 Specifications for Pressure-Vacuum Relief Valve

The pressure-vacuum relief valve shall be set to within ten (10) percent of the maximum allowable working pressure of the tank. The pressure-vacuum relief valve shall be permanently labeled with the operating pressure settings. The pressure-vacuum relief valve shall be properly installed and maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in a leak-free condition except when the operating pressure exceeds the valve set pressure.

5.3 Specifications for External Floating Roof Tanks

5.3.1 An external floating roof tank shall be:

5.3.1.1 Equipped with a floating roof consisting of a pan type that is installed before December 20, 2001, pontoon-type, or double-deck type cover, that rests on the surface of the liquid contents; and

5.3.1.2 Equipped with a closure device between the tank shell and roof edge consisting of two seals, one above the other; the one below shall be referred to as the primary seal, and the one above shall be referred to as the secondary seal.

5.3.1.3 The floating roof shall be floating on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled. When the roof is resting on the leg supports the processes of filling or emptying and refilling the tank shall be continuous and shall be accomplished as rapidly as possible. Whenever the operator intends to land the roof on its legs, an operator shall notify the APCO in writing at least ~~five~~ three calendar days prior to performing the work. The tank must be in compliance with this rule before the operator may land the roof on its legs. The required information to be included in the written notification as well as the recordkeeping requirements is specified in Section 6.3.7.

5.3.2 Seal designs shall be submitted to the APCO and shall not be installed or used unless they are approved by the APCO as meeting the criteria set forth in Sections 5.3.2.1 through 5.3.2.3 as applicable. Seal designs other than set forth in Sections 5.3.2.1 through 5.3.2.3 may be approved provided that a notice allowing the use of such design has been published in the Federal Register pursuant to CFR 40 Part 60: Subpart Kb paragraph 60.114b.

5.3.2.1 Welded Tanks with Primary Metallic-Shoe Type Seal

5.3.2.1.1 No gap between the tank shell and the primary seal shall exceed one and one half (1-1/2) inches. The cumulative length of all gaps between the tank shell and the primary seal greater than one-half (1/2) inch shall not exceed ten (10) percent of the circumference of the tank. The cumulative length of all primary seal gaps greater than one-eighth (1/8) inch shall not exceed 30 percent of the tank circumference. No continuous gap greater than one-eighth (1/8) inch shall exceed ten (10) percent of the tank circumference.

5.3.2.1.2 No gap between the tank shell and the secondary seal shall exceed one-half (1/2) inch. The cumulative length of all gaps between the tank shell and the secondary seal, greater than one-eighth (1/8) inch shall not exceed five (5) percent of the tank circumference.

5.3.2.1.3 Metallic-shoe-type seals shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 24 inches above the stored liquid surface.

5.3.2.1.4 The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell is no greater than double the gap allowed by the seal gap criteria specified in Section 5.3.2.1.1 for a length of at least 18 inches in the vertical plane above the liquid surface.

5.3.2.1.5 There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal.

5.3.2.1.6 The secondary seal shall allow easy insertion of probes up to one and one-half (1-1/2) inches in width in order to measure gaps in the primary seal.

5.3.2.1.7 The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal.

5.3.2.2 Riveted Tank with Primary Metallic-Shoe Type Seal

5.3.2.2.1 No gap between the tank shell and the primary seal shall exceed two and one-half (2-1/2) inches. The cumulative length of all primary seal gaps greater than one and one-half (1-1/2) inches shall be not exceed ten (10) percent of the circumference of the tank. The cumulative length of all gaps between the tank shell and the primary seal greater than one-eighth (1/8) inch shall not exceed 30 percent of the circumference of the tank. No continuous gap greater than one-eighth (1/8) inch shall exceed ten (10) percent of the tank circumference.

5.3.2.2.2 No gap between the tank shell and the secondary seal shall exceed one-half (1/2) inch. The cumulative length of all gaps between the tank shell and the secondary seal greater than one-eighth (1/8) inch shall not exceed five (5) percent of the tank circumference.

5.3.2.2.3 Metallic shoe-type seals shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 24 inches above the stored liquid surface. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell is no greater than double the gap allowed by the seal gap criteria specified in Section 5.3.2.2.1 for a length of at least 18 inches in the vertical plane

5.3.2.2.4 There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal.

5.3.2.2.5 The secondary seal shall allow easy insertion of probes up to two and one-half (2-1/2) inches in width in order to measure gaps in the primary seal.

5.3.2.2.6 The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal.

5.3.2.3 Tanks with Primary Resilient Toroid Seal:

5.3.2.3.1 The primary resilient toroid seal shall be mounted on the perimeter of the roof such that it is in contact with the tank's liquid contents at all times while the roof is floating.

5.3.2.3.2 No gap between the tank shell and the primary seal shall exceed one-half (1/2) inch. The cumulative length of all primary seal gaps greater than one-eighth (1/8) inch shall not exceed five (5) percent of the tank circumference. No continuous gap greater than one-eighth (1/8) inch shall exceed ten (10) percent of the tank circumference.

5.3.2.3.3 No gap between the tank shell and the secondary seal shall exceed one-half (1/2) inch. The cumulative length of all gaps between the tank shall and the secondary seal, greater than one-eighth (1/8) inch shall not exceed five (5) percent of the tank circumference.

5.3.2.3.4 There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal.

5.3.2.3.5 The secondary seal shall allow easy insertion of probes up to one-half (1/2) inch in width in order to measure gaps in the primary seal.

5.3.2.3.6 The secondary seal shall extend from the roof of the tank to the shell and not be attached to the primary seal.

5.3.2.4 The following seal designs have been found to be equivalent to seals meeting the criteria set forth in Sections 5.3.2.1 through 5.3.2.3:

5.3.2.4.1 When installed and maintained with zero gap:

MANUFACTURER	MODEL
Republic Fabricators	WeatherGuard Seal

5.3.2.4.2 When installed and maintained to meet the gap criteria for primary and secondary seals set forth in Sections 5.3.2.1 through 5.3.2.3:

MANUFACTURER	MODEL
"HMT"	Dual/Multi Blade Wiper Seals

5.4 Specifications for Internal Floating Roof Tanks

5.4.1 Internal floating roof tanks shall be equipped with seals that meet the criteria set forth in Section 5.3, except for complying with the requirement specified in Section 5.3.2.1.3. For internal floating roof, the metallic-shoe type seals shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of ~~18~~6 inches above the stored liquid surface.

5.4.2 The following seal designs have been found to be equivalent to seals meeting the criteria set forth in Section 5.3:

5.4.2.1 When installed and maintained with zero gap:

MANUFACTURER	MODEL
Ultraflote	Single Ultraseal

5.4.2.2 When installed and maintained to meet the gap criteria for primary and secondary seals set forth in Sections 5.3.2.1 through 5.3.2.3:

MANUFACTURER	MODEL
Ultraflote	Dual Ultraseal
Altech	Double Wiper Seal

5.4.3 The operator shall comply with the floating roof landing requirements specified in Section 5.3.1.3.

5.5 Floating Roof Deck Fitting Requirements

5.5.1 All openings in the roof used for sampling or gauging, except for pressure-vacuum relief valves complying with Section 5.2, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal, or lid. The cover, seal, or lid shall at all times be in a closed position, with no visible gaps and leak-free, except when the device or appurtenance is in use for sampling or gauging.

5.5.2 Tanks shall meet the requirements of Sections 5.1.3, 5.5.1, and Sections 5.5.2.1 through 5.5.2.4.

5.5.2.1 Requirements for Internal Floating Roof Deck Fittings

5.5.2.1.1 Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface.

5.5.2.1.2 Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, combination manway/vacuum breakers, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e., no visible gap) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use.

5.5.2.1.3 Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports.

5.5.2.1.4 Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or set to open at the manufacturer's recommended setting.

5.5.2.1.5 Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable.

5.5.2.1.6 Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable.

5.5.2.2 Requirements for External Floating Roof Deck Fittings

5.5.2.2.1 Except for automatic bleeder vents and rim vents and pressure-vacuum relief ~~vents~~ valves, each opening in a non-contact external floating roof shall provide a projection below the liquid surface.

5.5.2.2.2 Except for automatic bleeder vents and rim vents, roof drains, and leg sleeves, each opening in the roof shall be equipped with a gasketed cover, seal, or lid that shall be maintained in a closed position at all times (i.e., no visible gap) except when in actual use.

5.5.2.2.3 Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

5.5.2.2.4 Rim vents shall be equipped with a gasket and shall be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

5.5.2.2.5 Each emergency roof drain shall be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening. The fabric cover must be impermeable if the liquid is drained into the contents of the tanks.

5.5.2.2.6 External floating roof legs shall be equipped with vapor socks or vapor barriers in order to maintain a leak-free condition so as to prevent VOC emissions from escaping through the roof leg opening.

5.5.2.3 Solid Guidepole

Solid sampling or gauging wells, and similar fixed projections through a floating roof such as an anti-rotational pipe, shall meet the following requirements:

5.5.2.3.1 The well shall provide a projection below the liquid surface.

5.5.2.3.2 The well shall be equipped with a pole wiper and a gasketed cover, seal or lid which shall be in a closed position at all times (i.e., no visible gap) except when the well is in use.

5.5.2.3.3 The gap between the pole wiper and the guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed one-half (1/2) inch.

5.5.2.4 Slotted Guidepole

Slotted sampling or gauging wells shall meet the following requirements:

5.5.2.4.1 The well shall provide a projection below the liquid surface.

5.5.2.4.2 The well on external floating roof shall be equipped with the following: a sliding cover, a well gasket, a pole sleeve, a pole wiper, and an internal float and float wiper designed to minimize the gap between the float and the well, and provided the gap shall not exceed one-eighth (1/8) inch; or shall be equipped with a well gasket, a zero gap pole wiper seal and a pole sleeve that projects below the liquid surface.

5.5.2.4.3 The gap between the pole wiper and the guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed one-eighth (1/8) inch.

5.6 Specifications for Vapor Recovery Systems

5.6.1 Fixed roof tanks shall be fully enclosed and shall be maintained in a leak-free condition. An APCO-approved vapor recovery system shall consist of a closed system that collects all VOCs from the storage tank, and a VOC control device. The vapor recovery system shall be maintained in a leak-free condition. The VOC control device shall be one of the following:

5.6.1.1 A condensation or vapor return system that connects to one of the following: a gas processing plant, a field gas pipeline, a pipeline distributing Public Utility Commission quality gas for sale, an injection well for disposal of vapors as approved by the ~~Department of Oil, Gas, and Geothermal Resources (DOGGR)~~ California Geologic Energy Management Division (CalGEM).

5.6.1.2 A VOC control device that reduces the inlet VOC emissions by at least 95 percent by weight as determined by the test method specified in Section 6.4.6.

5.6.2 Any tank gauging or sampling device on a tank vented to the vapor recovery system shall be equipped with a leak-free cover which shall be closed at all times except during gauging or sampling.

5.6.3 All piping, valves, and fittings shall be constructed and maintained in a leak-free condition.

5.7 Voluntary Tank Preventive Inspection and Maintenance, and Tank Interior Cleaning Program

Until June 30, 2024, ~~Only~~ operators who elect to participate in the voluntary tank preventive inspection and maintenance, and tank interior cleaning program (program) shall be allowed to use the provisions specified in Tables ~~3~~5 to ~~5~~7 and Section 5.7.5. When using Tables ~~3~~5 to ~~5~~7 and Section 5.7.5 provisions, operators shall perform the procedures as expeditiously as practicable and minimize emissions to the maximum extent practicable. To participate in this program, the operator shall comply with the requirements of Sections 5.7.1 through 5.7.4.

5.7.1 Submit a letter to the APCO prior to conducting tank inspection, maintenance, and cleaning activities. The letter shall contain a list of each tank that will be subject to this program. The list shall include the tank identification number and location, and/or PTO numbers.

5.7.2 Keep in their facility at all times a copy of the letter sent to the APCO and maintain the records of annual tank inspection, maintenance and cleaning activities, to document their participation in the program.

5.7.3 The absence of a copy of the letter and/or failure to maintain appropriate records shall be deemed as non-participation in the program, and therefore the operator will not be eligible to use the provisions specified in Tables ~~3~~5 to ~~5~~7 and Section 5.7.5. Those who have not voluntarily participated in the program but are found to be using the provisions of Tables ~~3~~5 to ~~5~~7, and Section 5.7.5 shall be deemed to be in violation of this rule.

5.7.4 Operators who elect to participate in this program but who fail to comply with all of the requirements specified in Tables 3 ~~to~~and ~~5~~4 and Section 5.7.5 shall be deemed to be a violation of the provisions of this rule.

5.7.5 Storage Tank Degassing and Interior Cleaning Requirements

After June 30, 2024, operators of Fixed and Floating Roof Tanks shall comply with the provisions of Section 5.7.5. Operators may disconnect from vapor recovery provided that the procedures are performed as expeditiously as practicable and emissions are minimized to the maximum extent practicable.

5.7.5.1 Notification

Operators of storage tanks subject to the requirements of Section 5.7 shall notify the APCO in writing at least three (3) days prior to performing tank degassing and interior tank cleaning activities. Written notification shall include the following information:

5.7.5.1.1 The PTO number and physical location of the tank being degassed,

5.7.5.1.2 The date and time that tank degassing and cleaning activities will begin,

5.7.5.1.3 The degassing method, as allowed pursuant to Section 5.7.5.4, to be used,

5.7.5.1.4 The method to be used to clean the tank, including any solvents to be used, and

5.7.5.1.5 The method to be used to dispose of the removed sludge, including methods that will be used to control emissions from the receiving vessel and emissions during transport.

5.7.5.2 Records

Operators shall maintain records of tank cleaning activities for a period of 5 years and present said records to the APCO upon request. Records should include the final details of the planned activities submitted pursuant to Section 5.7.5.1.

5.7.5.3 Fixed-Roof Tanks Operating Only a Pressure-Vacuum Relief Valve

5.7.5.3.1 Except for complying with Section 5.7.5.3.2 requirements, fixed-roof tanks allowed, pursuant to Tables ~~1~~3, ~~and2~~4, 5, and 6 of this rule, to operate with a pressure-vacuum relief valve ~~as the primary VOC control system~~ are not subject to the degassing requirements specified in Section 5.7.5.4.

5.7.5.3.2 Operators shall comply with the requirements of Section 5.2 during the process of draining, and refilling the tank

with an organic liquid having a TVP of 0.5 psia or greater until June 30, 2024, or TVP of 0.1 psia or greater after June 30, 2024.

5.7.5.3.3 The requirements specified in Sections 5.1 and 5.2 shall not apply to the tank during interior cleaning or maintenance activities.

5.7.5.4 Tank Degassing Requirements

Except for tanks satisfying Section 5.7.5.3 provisions, the process of tank degassing shall be accomplished by emptying the tank of organic liquid having a TVP of 0.5 psia until June 30, 2024, or TVP of less than 0.1 psia after June 30, 2024, or greater, and minimizing organic vapors in the tank vapor space by one of the following methods:

5.7.5.4.1 Exhaust VOCs contained in the tank vapor space to an APCO-approved vapor recovery system until the organic vapor concentration is 5,000 ppmv or less, or is 10 percent or less of the lower explosion limit (LEL), whichever is less; or

5.7.5.4.2 Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable liquid until 90 percent or more of the maximum operating level of the tank is filled. Suitable liquids are organic liquids having a TVP of less than 0.5 psia until June 30, 2024, or TVP of less than 0.1 psia after June 30, 2024, water, clean produced water, or produced water derived from crude oil having a TVP less than 0.5 psia; or

5.7.5.4.3 Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable gas. Degassing shall continue until the operator has achieved a vapor displacement equivalent to at least 2.3 times the tank capacity. Suitable gases are air, nitrogen, carbon dioxide, or natural gas containing less than 10 percent VOC by weight; or

5.7.5.4.4 For free-water knockout tanks, the operator may degas the tank vapor space by restricting the outflow of water and floating off the oilpad, such that at least 90 percent of the tank volume is displaced.

5.7.5.4.5 During degassing, the operator shall discharge or displace organic vapors contained in the tank vapor space to an APCO-approved vapor recovery system that is leak-free and meets the requirements of Section 5.6.1.1 or Section 5.6.1.2.

5.7.5.4.6 To facilitate connection to an external APCO-approved vapor recovery system a suitable tank fitting, such as a manway, may be temporarily removed for a period of time not to exceed 1 hour.

5.7.5.4.7 Except as provided for in Section 5.7.5.4.9, the tank shall be in compliance with the applicable requirements specified in Section 5.1 through Section 5.6 during draining, degassing, and refilling the tank with an organic liquid having a TVP of 0.5 psia or greater <u>until June 30, 2024, or TVP of less than 0.1 psia after June 30, 2024, or greater</u>.

5.7.5.4.8 Draining and refilling of floating roof tanks shall occur as a continuous process and shall proceed as rapidly as practicable while the roof is not floating on the surface of the stored liquid.

5.7.5.4.9 For floating-roof tanks, the gap seal requirements specified in Sections 5.3.2 and 5.4.2 shall not apply while the roof is resting on its legs, and during the processes of draining, degassing, or refilling the tank. The leak-free condition specified in Section 5.1.3 shall not apply during refilling the tank, if the operator complies with Section 5.7.5.4.8 requirements.

5.7.5.4.10 After a tank has been degassed pursuant to the provisions of Section 5.7.5 the requirements specified in Section 5.1 through Section 5.6 shall not apply until an organic liquid having a TVP of 0.5 psia or greater <u>until June 30, 2024, or TVP of less than 0.1 psia after June 30, 2024, or greater</u> is placed, held, or stored in the tank.

5.7.5.5 Tank Cleaning

5.7.5.5.1 While performing tank cleaning activities, operators may use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302°F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams per liter VOC content or less.

5.7.5.5.2 Steam cleaning shall be allowed at locations where wastewater treatment facilities are limited or during the months of December through March.

5.7.5.6 Removed Sludge

Operators of tanks containing an organic liquid with a TVP of 1.5 psia or greater shall control emissions from the removed sludge by complying with all of the following provisions:

5.7.5.6.1 During sludge removal the operator shall control emissions from the receiving vessel by operating an APCO-approved vapor control device that reduces emissions of organic vapors by at least 95 percent.

5.7.5.6.2 Operators shall transport removed sludge in closed, liquid leak-free containers.

5.7.5.6.3 Notwithstanding Section 5.7.5.6.2, operators shall store removed sludge, until final disposal, in leak-free containers, or tanks complying with Section 5.1 requirements. Sludge that is to be used to manufacture roadmix, as defined in Rule 2020 (Exemptions), is exempt from this requirement. Roadmix manufacturing operations exempt pursuant to Rule 2020, shall maintain documentation of their compliance with Rule 2020, and promptly make said documentation available to the APCO upon request.

Table ~~3~~5: Fixed Roof Tank Preventive Inspection and Maintenance until June 30, 2024 Emission Minimization for Components Serving Organic Liquid Storage Tanks			
Components	Maintenance Schedule	Emission Minimization	Additional Requirements
1. Hatch 2. Tank seals and seams 3. Cable Seals 4. Piping components directly affixed to the tank and within five feet of the tank, including but not limited to: -Valves -Flanges -Connectors	1. Conduct annual inspections with maintenance and repair of components. 2. Conduct visual inspections and inspections using a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21. 3. Visually or ultrasonically inspect as appropriate, the external shells and roofs of un-insulated tanks for integrity annually.	1. Liquid Leak Repair leaking components that have a liquid leak rate of ≥30 drops per minute, within 8 hours after detection. Repair leaking components that have a liquid leak rate of ≥3 to <30 drops per minute within 24 hours after detection. 2. Gas leak Comply with the following requirements to repair leaking components that have a gas leak >10,000 ppmv (measured in accordance with EPA Method 21 by a portable hydrocarbon detection instrument that is calibrated with methane): a. Eliminate the leak within 8 hours after detection; or b. If the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices; and c. Eliminate the leak within 48 hours after minimization; and d. In no event that the total time to minimize and eliminate the leak shall exceed 56 hours after detection. 3. If a component type for a given tank is found to leak during an annual inspection, then conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If a component type is found to have no leak after four consecutive quarterly inspections, then revert to annual inspections.	1. For leaking components, immediately affix a tag and maintain records of liquid leak and gas leak detection readings, date/time leak was discovered, and date/time the component was repaired to a leak-free condition. 2. Leaking components that have been discovered by the operator that have been immediately tagged and repaired within the deadlines specified in the Emissions Minimization requirements, shall not constitute a violation of this rule. However, leaking components discovered during inspections by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within deadlines specified in the Emissions Minimization requirements, shall constitute a violation of this rule. 3. Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if it is under the voluntary inspection and maintenance program.

Table 46: External Floating Roof Tank Preventive Inspection and Maintenance until June 30, 2024			
Emission Minimization for Components Serving Organic Liquid Storage Tanks			
Components	Maintenance Schedule	Emission Minimization	Additional Requirements
1. Piping Components (valves, flanges, and connectors) directly affixed to the tank and within five feet of the tank.	1. Conduct annual inspections with maintenance and repair of components. 2. Conduct visual inspections and inspections using a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21. 3. Visually or ultrasonically inspect as appropriate, the external shells and roofs of uninsulated tanks for integrity annually.	1. Liquid Leak Repair leaking components that have a liquid leak rate of ≥30 drops per minute within 8 hours after detection. Repair leaking components that have a liquid leak rate of ≥3 to <30 drops per minute within 24 hours after detection. 2. Gas leak Comply with the following requirements to repair leaking components that have a gas leak >10,000 ppmv (measured in accordance with EPA Method 21 by a portable hydrocarbon detection instrument that is calibrated with methane): a. Eliminate the leak within 8 hours after detection; or b. If the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices; and c. Eliminate the leak within 48 hours after minimization; and d. In no event that the total time to minimize and eliminate the leak shall exceed 56 hours after detection. 3. If a component type for a given tank is found to leak during annual inspection, then conduct quarterly inspections on the tank or tank system for four consecutive quarters. If a component type is found to have no leak after four consecutive quarterly inspections, then revert to annual inspections.	1. For leaking components, immediately affix a tag and maintain records of liquid leak and gas leak detection readings, date/time leak was discovered, and date/time the component was repaired to a leak-free condition. 2. Leaking components that have been discovered by the operator that have been immediately tagged and repaired within the deadlines specified in the Emissions Minimization requirements, shall not constitute a violation of this rule. However, leaking components discovered during inspections by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within deadlines specified in the Emissions Minimization requirements, shall constitute a violation of this rule. 3. Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if it is under the voluntary inspection and maintenance program.

Table ~~5~~7: Internal Floating Roof Preventive Inspection Maintenance until June 30, 2024 Emission Minimization for Components Serving Organic Liquid Storage Tanks			
Components	Maintenance Schedule	Emission Minimization	Additional Requirements
1. Piping Components (valves, flanges, and connectors) directly affixed to the tank and within five feet of the tank.	1. Conduct annual inspections with maintenance and repair of components. 2. Conduct visual inspections and inspections using a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21. 3. Externally inspect un-insulated tanks, tank shells, and roofs for integrity annually.	1. Liquid Leak Repair leaking components that have a liquid leak rate of ≥30 drops per minute, within 8 hours after detection. Repair leaking components that have a liquid leak rate of ≥3 to <30 drops per minute within 24 hours after detection. 2. Gas leak Comply with the following requirements to repair leaking components that have a gas leak >10,000 ppmv (measured in accordance with EPA Method 21 by a portable hydrocarbon detection instrument that is calibrated with methane): a. Eliminate the leak within 8 hours after detection; or b. If the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices; and c. Eliminate the leak within 48 hours after minimization; and d. In no event that the total time to minimize and eliminate the leak shall exceed 56 hours after detection. 3. If a component type for a given tank is found to leak during annual inspection, then conduct quarterly inspections on the tank or tank system for four consecutive quarters. If a component type is found to have no leak after four consecutive quarterly inspections, then revert to annual inspections.	1. For leaking components, immediately affix a tag and maintain records of liquid leak and gas leak detection readings, date/time leak was discovered, and date/time the component was repaired to a leak-free condition. 2. Leaking components that have been discovered by the operator that have been immediately tagged and repaired within the deadlines specified in the Emissions Minimization requirements, shall not constitute a violation of this rule. However, leaking components discovered during inspections by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within deadlines specified in the Emissions Minimization requirements, shall constitute a violation of this rule. 3. Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if it is under the voluntary inspection and maintenance program.

5.8 Preventive Maintenance and Interior Cleaning Requirements for Fixed Roof Tanks (Effective after June 30, 2024)

5.8.1 Conduct maintenance and cleaning activities pursuant to Section 5.7.5.

5.9 Inspection and Re-Inspection Requirements (Effective after June 30, 2024)

5.9.1 Determination of Compliance with the Leak Standards during District Inspection

For the purpose of this rule, a facility shall be considered in violation if one or more of the conditions specified in Sections 5.9.1.1 through 5.9.1.4 exist at the facility.

5.9.1.1 The discovery of a major gas leak greater than 10,000 ppmv.

5.9.1.2 The discovery of a liquid leak as defined in Section 3.23.

5.9.1.3 Exceeding the allowable number of minor leaks defined in Table 8.

Table 8 – Allowable Leaks

Leak Threshold	200 or Less Components Inspected*	More than 200 Components Inspected*
500-10,000ppmv	5	2% of total inspected

*The maximum number of leaks in Table 8 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components inspected during the specified inspection period. Leaks counted toward the allowable leak threshold in Table 8 are still subject to the maintenance and repair requirements of Section 5.9.3 through 5.9.4.

5.9.1.4 Failure to repair leaks within the timeframes specified in Table 9.

5.9.2 Determination of Compliance with the Leak Standards during Operator Inspection

For the purpose of this rule a facility shall be considered in violation if the following condition specified in Section 5.9.2.1 exists at the facility.

5.9.2.1 Failure to repair leaks within the timeframes specified in Table 9.

5.9.3 A leak discovered during Operator and District Inspection(s) above the leak threshold defined in Section 3.14 and in Table 2 shall be repaired within the timeframes of Table 9.

Table 9 – Repair Time Periods	
Leak Threshold	Repair Time Period
Minor Leak	14 Calendar Days
Major Leak	2 Calendar Days
Liquid Leak	2 Calendar Days

5.9.4 At least once each calendar quarter all components shall be tested for leaks, except for inaccessible components, unsafe to monitor components and floating roof tanks including their deck fittings and components.

External floating roof tanks shall be inspected once every 12 months as required by Section 6.1.3.

Internal floating roof tanks shall be inspected once every 60 months as required by Section 6.1.4.

Inspections shall be performed as allowed by the following:

5.9.4.1 All components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) in accordance with US EPA Reference Method 21 as specified in Section 6.4.8.

5.9.4.2 Inaccessible components and unsafe-to-monitor components shall be inspected once every 12 months per US EPA Reference Method 21.

5.9.4.3 Except for inaccessible components, unsafe to monitor components, and floating roof tanks including deck fittings and components, owners or operators shall audio-visually inspect (by hearing and by sight) all hatches, pressure-vacuum relief valves, pressure relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours.

5.9.4.4 Any audio-visual inspection specified in Section 5.9.4.3 that indicates a leak shall be tested using US EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance with the repair timeframes specified in Table 9.

5.9.4.5 An operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 72 hours of placing the component in service.

5.9.4.6 A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator.

5.9.4.7 Upon detection of a component with a leak concentration measured above the standards specified, the owner or operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of leak detection measurement and the measured leak concentration. The tag shall remain affixed to the leaking component until it has been successfully repaired or replaced, after which the tag shall be removed.

5.9.4.7.1 Successful repair shall be confirmed by re-measuring the components using US EPA Reference Method 21 to determine that the component is below the minimum leak threshold after repair or replacement.

5.9.4.8 Excluding tanks, components or component parts which incur five (5) repair actions within a rolling 12-month period shall be replaced with a compliant component in working order and must be re-measured using US EPA Reference Method 21, to determine that the component is below the minimum leak threshold. A record of the replacement must be maintained in a log at the facility, and shall be made available upon request by the APCO.

Failure to comply with all of the Maintenance Requirements of Section 5.9.4.1 through 5.9.4.8 shall constitute a violation of this rule.

5.9.4.9 An operator shall attempt to minimize all component leaks immediately to the extent possible, but no later than one (1) hour after detection of leak in order to stop or reduce leakage to the atmosphere.

5.9.4.10 If the leak has been minimized but the leak still exceeds the applicable leak standards of this rule, an operator shall comply with at least one of the requirements of Sections 5.9.4.10.3, 5.9.4.10.4 or 5.9.4.10.5 as soon as practicable but not later than the time period specified in Table 9.

5.9.4.10.1 The leak rate measured, after leak minimization has been performed, shall be the leak rate used to determine the repair period specified in Table 9.

5.9.4.10.2 The start of the repair period shall be the time of the initial leak detection.

5.9.4.10.3 Repair or replace the leaking component; or

5.9.4.10.4 Vent the leaking component to a VOC control system as defined in Section 3.1.

5.9.4.10.5 Remove the leaking component from operation.

6.0 Administrative Requirements

6.1 Inspection of Floating Roof Tanks

6.1.1 The operator of external floating roof tanks shall make the primary seal envelope available for unobstructed inspection by the APCO on an annual basis at locations selected along its circumference at random by the APCO. In the case of riveted tanks with toroid-type seals, a minimum of eight (8) locations shall be made available; in all other cases, a minimum of four (4) locations shall be made available. If the APCO suspects a violation may exist the APCO may require such further unobstructed inspection of the primary seal as may be necessary to determine the seal condition for its entire circumference.

6.1.2 Operators of floating roof tanks shall submit a tank inspection plan to the APCO for approval. The plan shall include an inventory of the tanks subject to this rule and a tank inspection schedule. A copy of the operator's tank safety procedures shall be made available to the APCO upon request. The tank inventory shall include tank's identification number, PTO number, maximum tank capacity, dimensions of tank (height and diameter), organic liquid stored, type of primary and secondary seal, type of floating roof (internal or external floating roof), construction date of tank, and location of tank. Any revision to a previously approved tank inspection schedule shall be submitted to the APCO for approval prior to conducting an inspection.

6.1.3 External Floating Roof Tank Inspection

6.1.3.1 Inspect all floating roof tanks at least once every 12 months to determine compliance with the requirements of this rule. The actual gap measurements of the floating roof primary and secondary seals shall be recorded. The inspection results shall be submitted to the APCO as specified in Section 6.3.5.

6.1.3.2 Inspect the primary and secondary seals for compliance with the requirements of this rule every time a tank is emptied or degassed. Actual gap measurements shall be performed when the liquid level is static but not more than 48 hours after the tank roof is re-floated.

6.1.4 Internal Floating Roof Tank Inspection

6.1.4.1 For newly constructed, repaired, or rebuilt internal floating roof tanks, visually inspect the internal floating roof and its appurtenant parts, fittings, etc., and measure the gaps of the primary seal and/or secondary seal prior to filling the tank. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., the operator shall repair the defects before filling the tank.

6.1.4.2 Visually inspect, through the manholes, roof hatches, or other openings on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found are violations of this rule.

6.1.4.3 Conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found shall constitute a violation of this rule. The inspection results shall be submitted to the APCO as specified in Section 6.3.5.

6.2 TVP and API Gravity Testing of Stored Organic Liquid in Uncontrolled Fixed Roof Tanks

Sections 6.2.1 and 6.2.2 shall not apply to tanks that exclusively store organic liquids listed in Appendix A, provided the storage temperature indicated in Appendix A is not exceeded at any time. An operator shall comply with Section 6.3.6 if the information in Appendix A is used to demonstrate the TVP and/or API gravity of the stored liquid.

6.2.1 ~~Initial~~ TVP and API Gravity Testing

6.2.1.1 An operator shall conduct ~~an initial~~ TVP and API testing upstream of each separator and ~~uncontrolled~~ fixed roof tank not controlled by a vapor control system per Sections 5.3, 5.4, 5.5, or 5.6 using test methods in Section 6.4 and the procedures below: ~~In lieu of testing each uncontrolled fixed roof tank, an operator may conduct a TVP testing of a representative tank provided the requirements of Sections 6.2.1.1.1 through 6.2.1.1.59 are met. The operator shall submit the records of TVP and/or API gravity testing to the APCO~~

~~as specified in Section 6.3.6. The operator shall be in full compliance with the rule by the deadline specified in Section 7.1~~

6.2.1.1.1 In lieu of testing upstream of each fixed roof tank not meeting the control systems of Sections 5.3, 5.4, 5.5, and 5.6 an operator may conduct TVP testing of a representative fixed roof tank. The selection of a representative, uncontrolled fixed roof tank~~s~~ is submitted in writing to the APCO, and written approval is granted by the APCO prior to conducting the test.

6.2.1.1.2 One ~~uncontrolled~~ fixed roof tank not meeting the control systems of Sections 5.3, 5.4, 5.5, and 5.6 represents some or all of the tanks in a tank battery (defined in Section 3.~~31~~41).

6.2.1.1.3 For crude oil production facilities, the representative uncontrolled fixed roof tank shall be the ~~first~~ front line tank (or tanks) in a tank battery that is first receiving the produced fluids (mixture of oil, water, and gases) from the crude oil production wells.

6.2.1.1.4 The stored organic liquid in each of the represented tank~~s~~ is the same and came from the same source.

6.2.1.1.5 The TVP and storage temperature of the stored organic liquid of the representative tank to be tested are the same or higher than those of the tanks it is to represent.

6.2.1.1.6 An operator must maintain a sketch or diagram of the separator and tank system depicting the sampling location.

6.2.1.1.7 The TVP testing shall be conducted during the months of June through September using the actual storage temperature of the organic liquid in the tank.

6.2.1.1.8 Testing shall occur whenever there is a change in the source or type of organic liquid stored in each tank. The operator shall submit the records of TVP and/or API gravity testing to the APCO as specified in Section 6.3.6.

6.2.1.1.9 An operator shall conduct a TVP and API testing of each fixed roof tank not controlled by a vapor control system per Sections 5.3, 5.4, 5.5, or 5.6 at least once every 24 months following the procedures in Section 6.2.1.

~~6.2.1.2 The TVP testing shall be conducted at actual storage temperature of the organic liquid in the tank. If the tank stores crude oil or petroleum distillates, the operator shall also conduct an API gravity testing.~~

~~6.2.1.3 In lieu of complying with Sections 6.2.1.1 and 6.2.1.2, an operator shall submit a complete application for an Authority to Construct to install and operate on each uncontrolled fixed roof tank the appropriate VOC control system specified in Section 5.1. The operator shall be in full compliance with the rule by the deadline specified in Section 7.1.~~

~~6.2.2 Periodic TVP and API Gravity Testing~~

~~Effective on and after November 15, 2003, an operator shall conduct a TVP testing of each uncontrolled fixed roof tank at least once every 24 months during summer (July – September), and/or whenever there is a change in the source or type of organic liquid stored in each tank. In lieu of testing each uncontrolled fixed roof tank, an operator may conduct a TVP testing of a representative tank provided the requirements of Sections 6.2.1.1.1 through 6.2.1.1.5 are met. The operator shall also comply with Section 6.2.1.2. The operator shall submit the records of TVP and/or API gravity testing to the APCO as specified in Section 6.3.6.~~

~~6.2.3 The requirements of Sections 6.2.1 and 6.2.2 shall not apply to the following tanks:~~

~~6.2.3.1 Tanks identified in Section 5.1.1, Table 1, Group A, that are permitted by the District to operate a pressure-vacuum relief valve complying with Section 5.2 requirements, and exclusively receive and/or store crude oil with a TVP of less than 11 psia,~~

~~6.2.3.2 Tanks identified in Section 5.1.2, Table 2, Group A, that are permitted by the District to operate a pressure-vacuum relief valve complying with Section 5.2 requirements, and exclusively receive and/or store crude oil with a TVP of less than 11 psia, or~~

~~6.2.3.3 Tanks identified in Section 5.1.2, Table 2, Group B, are permitted by the District to operate a pressure-vacuum relief valve complying with Section 5.2 requirements; exclusively receive and/or store crude oil with a TVP of less than 11 psia; and have a permitted throughput of less than 150 barrels of crude oil per day.~~

6.3 Recordkeeping

An operator shall retain accurate records required by this rule for a period of five years. Records shall be made available to the APCO upon request, except for certain records that need to be submitted as specified in the respective sections below.

6.3.1 An operator whose tanks are subject to the requirements of this rule shall keep an accurate record of each organic liquid stored in each tank, including its storage temperature, TVP, and API gravity. The requirement of 6.3.1 shall not apply to fixed roof tanks equipped with a vapor recovery system, external floating roof tanks, or internal floating roof tanks that meet the requirements of this rule.

6.3.2 An operator whose emergency standby tanks are required to comply with Section 4.2.1 shall maintain records showing date(s) the organic liquid is first introduced into each tank, and date(s) each tank is fully drained. Such records shall be submitted to the APCO 60 days prior to permit renewal.

6.3.3 An operator whose temporary tanks are required to comply with Section 4.2.2 shall maintain records showing the tank capacity and duration of time that the tank is used.

6.3.4 Small producers shall maintain monthly records of average daily crude oil production to determine compliance with Section 3.~~29~~39. The monthly crude oil production records required by the ~~Department of Oil, Gas, and Geothermal Resources (DOGGR)~~California Geologic Energy Management Division (CalGEM) may be used to comply with the above requirement. Small producers shall also maintain monthly records of the average daily crude oil throughput of each tank to demonstrate compliance with Sections 4.3, and/or 5.1.2. Operators shall submit the required monthly records upon the request of the APCO.

6.3.5 An operator shall submit the reports of the floating roof tank inspections conducted in accordance with the requirements of Section 6.1 to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Sections 5.2 through 5.5. The inspection report for tanks that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and shall be made available upon request by the APCO. The inspection report shall contain all information necessary to demonstrate compliance with the provisions of this rule, including the following:

6.3.5.1 Date of inspection and names and titles of company personnel doing the inspection.

6.3.5.2 Tank identification numbers and PTO number.

6.3.5.3 Measurements of the gaps between the tank shell and primary and secondary seals.

6.3.5.4 Leak-free status of tanks and floating roof deck fittings. Records of leak-free status shall include the vapor concentration values measured in ppmv in accordance with the Test Method in Section 6.4.8.

6.3.5.5 Data, supported by calculations, demonstrating compliance with the requirements specified in Sections 5.3, 5.4, 5.5.2.3.3, 5.5.2.4.2, and 5.5.2.4.3 of this rule.

6.3.5.6 Any corrective actions or repairs performed on the tank in order to comply with this rule and the date such actions were taken.

6.3.6 An operator shall submit the records of TVP and API gravity testing conducted in accordance with the requirements of Section 6.2 to the APCO within 45 days after the date of testing. The record shall include the tank identification number, PTO number, type of stored organic liquid, TVP and API gravity of the stored organic liquid, test methods used, and a copy of the test results. An operator who uses the information in Appendix A to demonstrate the TVP and/or API gravity of the stored organic liquid shall submit information to the APCO within 45 days after the date that the type of organic liquid stored in the tank has been determined.

6.3.7 An operator shall maintain the records of the external floating roof or internal floating roof landing activities that are performed pursuant to Sections 5.3.1.3 and 5.4.3. The records shall include information on the TVP, API gravity, and type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. The operator shall keep the records at the facility (or on-site) for a period of five years. The records shall be made available to the APCO upon request.

6.3.8 An operator who is demonstrating that their tank PTE emissions are below six (6) tons of VOC per year or actual emissions are below four (4) tons of VOC per year shall keep an accurate record of each organic liquid stored in each tank, including storage temperature, TVP, and monthly throughput.

6.3.9 Inspection Log

The operator shall maintain an inspection log containing, at a minimum, all of the following information:

6.3.9.1 Total number of components inspected, and total number and percentage of leaking components found during inspection.

6.3.9.2 Location, type, name or description of each leaking component and description of any unit where the leaking component is found.

6.3.9.3 Date of leak detection and method of leak detection.

6.3.9.4 For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume.

6.3.9.5 Date of repair, replacement, or removal from operation of leaking components.

6.3.9.6 After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv.

6.3.9.7 Inspector's name, business mailing address, and business telephone number.

6.3.9.8 The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.

6.3.9.9 Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.

6.3.9.10 Copies of all records required by Section 6.3 of this rule shall be retained for a minimum of five (5) years after the date of an entry, and the records shall be made available to the APCO, CARB, and US EPA upon request.

6.4 Test and Inspection Methods

The following test methods shall be used unless otherwise approved by the APCO and the United States Environmental Protection Agency (US EPA).

6.4.1 Analysis of halogenated exempt compounds shall be conducted using California Air Resources Board (CARB) Method 432.

6.4.2 The API gravity of crude oil or petroleum distillate shall be determined by using ASTM Method D287-~~92~~12b (~~2000~~reapproved 2019)e1 "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)~~.~~ or ASTM Method D4052-18a "Standard Test Method for Density, Relative Density and API Gravity of Liquids by Digital Density meter", Sampling for API gravity shall be performed in accordance with ASTM Method D 4057-95 "Standard Practices for Manual Sampling of Petroleum and Petroleum Products".

6.4.3 Except for crude oil subject to Section 6.4.4, the TVP of any organic liquid shall be determined by measuring the Reid Vapor Pressure (RVP) using ASTM D 323-94 (Test Method for Vapor Pressure for Petroleum Products), and converting the RVP to TVP at the tank's maximum organic liquid storage temperature. The conversion of RVP to TVP shall be done in accordance with the procedures in Appendix B. Appendix B is an excerpt from the oil and gas section of "ARB Technical Guidance Document to the Criteria and Guidelines Regulation for AB 2588", dated August 1989. As an alternative to using ASTM D 323-94, the TVP of crude oil with an API gravity range of greater than 26° up to 30° may be determined by using other equivalent test methods approved by APCO, ARB and US EPA.

6.4.4 The latest version of the Lawrence Berkeley National Laboratory "Test Method for Vapor Pressure of Reactive Organic Compounds in Heavy Crude Oil Using Gas Chromatograph", as approved by ARB and US EPA, shall be used to determine the TVP of crude oil with an API gravity of 26° or less, or for any API gravity that is specified in this test method.

6.4.5 An operator may use the information in Appendix A to determine the TVP of the stored organic liquid in a tank provided the storage temperature listed in Appendix A is not exceeded at any time.

6.4.6 The control efficiency of any VOC destruction device, measured and calculated as carbon, shall be determined by US EPA Method 25, except when the outlet concentration must be below 50 ppm in order to meet the standard, in which case US EPA Method 25a may be used. US EPA Method 18 may be used in lieu of US EPA Method 25 or US EPA Method 25A provided the identity and approximate concentrations of the analytes/compounds in the sample gas stream are known before analysis with the gas chromatograph and the gas chromatograph is calibrated for each of the known analytes/compounds to ensure that the VOC concentrations are neither under- or over-reported.

6.4.7 Analysis of halogenated exempt compounds shall be analyzed by ARB Method 422 "Exempt Halogenated VOCs in Gases September 12, 1990".

6.4.8 Measurements of a gas-leak concentration shall be determined by US EPA Method 21.

6.4.8.1 After June 30, 2024, All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 9.

7.0 Compliance Schedule

~~7.1 Any tank subject to the requirements of this rule that is installed or constructed on and after May 19, 2005, shall be in full compliance with this rule upon initial operation, and thereafter.~~

7.~~2~~1 Any tank that is exempted under Section 4.0 that becomes subject to the VOC control system requirements of this rule through the loss of exemption status, shall be in full compliance with this rule on the date the exemption status is lost.

7.2 An operator shall comply with this rule in accordance with the schedule specified below:

Table 10 – Compliance Schedule

	Authority to Construct	Full Compliance
Leak Standards (Table 2), Inspection and Re-Inspection Requirements in Section 5.9	N/A	July 1, 2024
Tanks required to comply with Sections 5.1.1.1, 5.1.2.1, or required to install a pressure-vacuum relief valve	March 31, 2024	12 months after issuance of ATC

Appendix A
STORAGE TEMPERATURE VERSUS VAPOR PRESSURE

ORGANIC LIQUID	Reference Properties		Maximum Temp °F Not to Exceed	
	Gravity (°API)	Initial Boiling Point (°F)	0.5 (psia)	1.5 (psia)
Middle Distillates				
Kerosene	42.5	350	195	250
Diesel	36.4	372	230	290
Gas Oil	26.2	390	249	310
Stove Oil	23	421	275	340
Jet Fuels				
JP-1	43.1	330	165	230
JP-3	54.7	110	---	25
JP-4	51.5	150	20	68
JP-5	39.6	355	205	260
JP-7	44-50	360	205	260
Fuel Oil				
No. 1	42.5	350	195	250
No. 2	36.4	372	230	290
No. 3	26.2	390	249	310
No. 4	23	421	275	340
No. 5	19.9	560	380	465
Residual	19.27	---	405	---
No. 6	16.2	625	450	---
Asphalt				
60-100 pen.	---	---	490	550
120-150 pen.	---	---	450	500
200-300 pen.	---	---	360	420

Appendix A (Continued)
STORAGE TEMPERATURE VERSUS VAPOR PRESSURE

Organic Liquid	Reference Properties			Maximum Temperature (°F) Not to Exceed	
	Density (lb/gal)	Gravity °API	Initial Boiling Point (°F)	0.5 psia	1.5 psia
Acetone	6.6	47	133	---	35
Acrylonitrile	6.8	41.8	173	30	62
Benzene	7.4	27.7	176	34	70
Carbon Disulfide	10.6	22.1	116	---	10
Carbon Tetrachloride	13.4	---	170	20	63
Chloroform	12.5	---	142	---	40
Cyclohexane	6.5	49.7	177	30	65
1,2 Dichloroethane	10.5	---	180	35	75
Ethyl Acetate	7.5	23.6	171	38	70
Ethyl Alcohol	6.6	47.0	173	55	85
Isopropyl Alcohol	6.6	47.0	181	62	95
Methyl Alcohol	6.6	47.0	148	30	62
Methyl Ethyl Ketone	6.7	44.3	175	30	70
Toluene	7.3	30	231	75	120
Styrene	7.5		293	128	167
Vinyl Acetate	7.8	19.6	163	30	65

Appendix B

California Air Resources Board Technical Guidance
to the Criteria and Guidelines Regulation for AB 2588
(Partial Excerpt from pages 102, 103 and 104)

True Vapor Pressure (TVP)

RVP is the absolute pressure of volatile crude oil and nonviscous petroleum liquids. Numerically, the relationship between TVP, RVP and temperature can be expressed by the following equation:

$$TVP = (RVP)\, e^{[Co(IRTEMP - ITEMP)]}$$

Where: C_o = Constant dependent upon the value of RVP
ITEMP = $(1/559.69^oR)$
IRTEMP = $(1/(T_s + 459.69^oR))$
T_s = Temperature of the stored fluid in ^oF

The value of the constant term C_o depends upon the given value of RVP.

Values of C_o for different RVP numbers are tabulated in Table C-3. It should be noted, however, that an error was discovered in the API nomograph calculated values of TVP so that the RVP was not equal to TVP at 100^oF as was expected given the general definition of RVP. Using linear regression techniques, correction factors (C_F) were developed and should be added to the calculated values of TVP in order to obtain reasonable TVP numbers. The relationship between the three values is given as follows:

Corrected TVP = Calculated TVP + C_F

The correction factor was found to be dependent upon RVP according to the following equations:

If RVP < 3,

$C_F = (0.04) \times (RVP) + 0.1$

If RVP > 3,

$C_F = e^{[(2.3452061 \log (RVP)) - 4.132622]}$

Appendix B (Continued)

Table C-3: VALUES OF C_o FOR DIFFERENT RVP NUMBERS

RVP	C_o
0<RVP<2	-6622.5
2<RVP<3	-6439.2
RVP = 3	-6255.9
3<RVP<4	-6212.1
RVP = 4	-6169.2
4<RVP<5	-6177.9
RVP = 5	-6186.5
5<RVP<6	-6220.4
RVP = 6	-6254.3
6<RVP<7	-6182.1
RVP = 7	-6109.8
7<RVP<8	-6238.9
RVP = 8	-6367.9
8<RVP<9	-6477.5
RVP = 9	-6587.9
9<RVP<10	-6910.5
RVP = 10	-7234.0
10<RVP<15	-8178.0
RVP > 15	-9123.2

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RULE 4624 TRANSFER OF ORGANIC LIQUID (Adopted April 11, 1991; Amended September 19, 1991; Amended May 21, 1992; Amended December 17, 1992; Amended December 20, 2007; Amended [*rule adoption date*])

1.0 Purpose

The purpose of this rule is to limit Volatile Organic Compound (VOC) emissions from the transfer of organic liquids.

2.0 Applicability

This rule shall apply to organic liquid transfer facilities as defined in this rule.

3.0 Definitions

3.1 APCO: as defined in Rule 1020 (Definitions).

3.2 API: American Petroleum Institute.

3.3 ARB: The California Air Resource Board.

3.4 ASTM: American Society for Testing and Materials.

3.5 Background: the ambient concentration of organic compounds determined at least two (2) meters upwind from any valve or flange to be inspected and which is uninfluenced by any specific emission permit unit.

3.6 Bottom Loading: a type of organic liquid loading operation where the discharge opening into the container is completely submerged below the level of the organic liquid in the container.

3.7 CFR: Code of Federal Regulations.

3.8 Class 1 Organic Liquid Transfer Facility: any location transferring 20,000 gallons or more on any one day of organic liquids with a TVP of 1.5 psia or greater to or from tank trucks, trailers, or railroad tank cars.

3.9 Class 2 Organic Liquid Transfer Facility: any location transferring 4,000 gallons or more but less than 20,000 gallons on any one day of organic liquids with a TVP of 1.5 psia or greater to or from tank trucks, trailers, or railroad tank cars.

3.10 Closed VOC Emission Control System: an APCO-approved VOC emission control system that is not open to the atmosphere and that is composed of hard-piping, ductwork connections, and, if necessary, flow inducing devices that transport collected gases or vapors from a piece or pieces of equipment to a vapor return system or condensation system that connects to a process stream, a gas processing

plant, a gas pipeline recovery and distribution system (sales gas system), a fuel gas system, or an injection well for disposal of vapors as approved by the ~~Department of Oil, Gas, and Geothermal Resources (DOGGR)~~ California Geologic Energy Management Division (CalGEM).

3.11 Component: includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, flange, process drain, sealing mechanism, sight-glass, meter, or seal fluid system, separators, and pressure vessels in VOC service.

3.1~~1~~2 Container: any stationary tank, reservoir, or vessel in which any organic liquid is placed, held, or stored.

3.1~~2~~3 EPA: United States Environmental Protection Agency.

3.1~~3~~4 Excess Organic Liquid Drainage: more than ten (10) milliliters liquid drainage. Such liquid drainage for disconnect operations shall be determined by computing the average drainage from three consecutive disconnects at any one permit unit.

3.14~~5~~ Gasoline: any petroleum distillate, petroleum distillate/alcohol blend or alcohol having a Reid vapor pressure of four (4) pounds per square inch absolute or greater, which is used as a motor vehicle fuel, or any fuel which is commonly or commercially known or sold as gasoline.

3.1~~5~~6 Gasoline Bulk Plant: any loading facility and associated unloading facilities, storage tanks and vapor recovery system(s) used to load less than 20,000 gallons in any one (1) day of gasoline to delivery vessels (i.e., tank trucks or trailers).

3.1~~6~~7 IBP: Initial Boiling Point.

3.18 Inaccessible Component: a component that is located over 15 feet above ground when access is required from the ground; or a component that is located over six (6) feet away from a platform when access is required from the platform, or a component in a location that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.

3.1~~7~~9 Leak: the dripping of VOC-containing liquid at a rate of more than three (3) drops per minute; or

3.1~~7~~9.1 For organic liquids other than gasoline, ~~the detection~~ a reading in excess of the value specified in Table 1 or Table 2 ~~of any gaseous or vapor emissions a concentration of VOC greater than 1,000 ppmv above a background~~ as methane, above background on a portable hydocarbon detection instrument when measured in accordance with the test method in Section 6.3.8 that exceeds the values specified in Table 1 or Table 2. ~~shall constitute a leak.~~

Table 1 Leak in ppmv as Methane (Until June 30, 2024)	
	Leak
Component	1,000 and greater

Table 2 Leak in ppmv as Methane (After June 30, 2024)		
	Major Leak	Minor Leak
Component	1,000 and greater	500 to less than 1,000

3.1~~7~~9.2 For gasoline, a concentration of VOC greater than 10,000 ppmv, as methane, above background when measured in accordance with the test method in Section 6.3.8 shall constitute a leak.

3.1~~7~~9.3 Any liquid or gas coming from a component undergoing repair or replacement, or during sampling of process fluid from equipment into a container is not considered a leak provided such activities are accomplished as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere.

3.~~18~~20 Location: any single site at a building, structure, facility, or installation.

3.~~19~~21 Normal Business Hours: Monday through Friday, 8:00 am to 5:00 pm.

3.22 Optical Gas Imaging (OGI): an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

3.~~20~~23 Organic Liquid: any liquid which contains VOCs and has a TVP of 1.5 psia or greater at the storage container's maximum organic liquid storage temperature. Clean produced water, as defined by Rule 1020, and other types of liquids that contain no more than 35 milligrams of VOC per liter, shall not be considered to be an organic liquid.

3.~~21~~24 Organic Liquid Loading Operation: the transfer of organic liquid to a tank truck, trailer, or railroad car.

3.~~22~~25 Organic Liquid Transfer Facility: any aggregate or combination of transfer racks and vapor control equipment at a location, including, but not limited to, the stationary organic liquid pump, and the hose end connector, and the discharge of the vapor control device(s).

3.~~23~~26 Portable Hydrocarbon Detection Instrument: a hand-held hydrocarbon analyzer that meets the criteria specified in EPA Method 21, 40 CFR Part 60. The instrument shall be calibrated with methane.

3.27 Process Drain: any open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources.

3.~~24~~28 Psia: Pounds per square inch, absolute.

3.~~25~~9 Pump: a device used to transport fluids by the addition of energy, and includes all associated components used for connecting or sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the pump. For example, a valve that is connected to a threaded hole on body of the pump, the first VOC leak point is the threaded connection on the body side of the pump, but the valve itself is not a "first VOC leak point". Similarly, a pump shaft seal is considered as a first "VOC leak point".

3.30 Tag: a piece of paper, metal, plastic or other suitable material that is attached to a component for the purpose of identification or other information.

3.~~26~~31 Transfer Rack: a loading rack as defined in Rule 1020 (Definitions) or an unloading rack as defined in Rule 2020 (Exemptions). This rule applies only to racks with stationary pumps.

3.~~27~~32 ~~TVP: True~~ Vapor Pressure (TVP)~~.~~: the equilibrium partial vapor pressure exerted by an organic liquid at actual storage temperature as determined by the applicable test methods specified in Section 6.3.

3.33 Unsafe-to-Monitor Component: a component installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.

3.~~28~~34 Volatile Organic Compound (VOC): as defined in Rule 1020 (Definitions).

4.0 Exemptions

4.1 The requirements of Section 5.0 of this rule shall not apply to organic liquid transfer facilities which transfer less than 4,000 gallons of organic liquids ~~in any one day~~daily. The operator shall meet the applicable recordkeeping requirements of Section 6.1.1.

4.2 The requirements of this rule shall not apply to transfer operations subject to the requirements of Rule 4621 (Gasoline Transfer into Stationary Storage Containers, Gasoline Delivery Vessels and Gasoline Bulk Plants) or to transfer operations that are subject to Rule 4622 (Gasoline Transfer into Motor Vehicle Fuel Tanks).

4.3 Except for Section 6.1, the requirements of this rule shall not apply to the transfer of organic liquids with TVP less than 1.5 psia at the storage container's maximum organic liquid storage temperature.

4.4 The requirements of Section 5.9 shall not apply to equipment or components subject to:

4.4.1 Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities);

4.4.2 Rule 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants); or

4.4.3 Rule 4623 (Storage of Organic Liquids).

4.5 Except for the one-time record submission requirement of Section 6.1.5 for vacuum truck operators, the requirements of this rule shall not apply to transfer operations involving vacuum trucks.

5.0 Requirements

5.1 For a Class 1 organic liquid transfer facility, the emission of VOC from the transfer operation shall not exceed 0.08 pounds per 1,000 gallons of organic liquid transferred and use one of the following systems:

5.1.1 An organic liquid loading operation shall be bottom loaded.

5.1.2 The VOC from the transfer operation shall be routed to:

5.1.2.1 A vapor collection and control system;

5.1.2.2 A fixed roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids);

5.1.2.3 A floating roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or

5.1.2.4 A pressure vessel equipped with an APCO-approved vapor recovery system that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or

5.1.2.5 A closed VOC emission control system.

5.2 A Class 2 organic liquid transfer facility shall prevent the release to the atmosphere of at least 95 percent by weight of the VOC displaced during organic liquid transfers and use one of the following systems:

5.2.1 An organic liquid loading operation shall be bottom loaded, equipped with a vapor collection and control system and the vapors from loading the tank truck, trailer, or railroad tank car shall be routed to the vapor collection and control system; or

5.2.2 The VOC from the transfer operation shall be routed to:

5.2.2.1 A vapor collection and control system; or

5.2.2.2 A fixed roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or

5.2.2.3 A floating roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or

5.2.2.4 A pressure vessel equipped with an APCO-approved vapor recovery system that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or

5.2.2.5 A closed VOC emission control system.

5.3 A transfer operation utilizing a closed VOC emission control system or utilizing a container that meets the control requirements of Rule 4623 (Storage of Organic Liquids) to meet the emission control requirements of this rule shall demonstrate compliance with Sections 5.1 and 5.2 by complying with the leak inspection requirements of Section 5.9.

5.4 The vapor collection and control system shall operate such that the pressure in the delivery tank being loaded does not exceed 18 inches water column pressure and six (6) inches water column vacuum. This section shall not apply to the transfer of liquefied petroleum gas.

5.5 All delivery tanks which previously contained organic liquids with a TVP of 1.5 psia or greater at the storage container's maximum organic liquid storage temperature shall be filled only at transfer facilities satisfying Sections 5.1, 5.2, or 5.4, as applicable.

5.6 The transfer rack and vapor collection equipment shall be designed, installed, maintained and operated such that there are no major leaks and no excess organic liquid drainage at disconnections.

5.7 The construction of any new top loading facility or the reconstruction, as defined in 40 CFR 60.15, or the expansion of any existing top loading facility with top loading equipment shall not be allowed.

5.8 Notwithstanding any other provision of this rule, organic liquid transfer facilities exclusively handling liquefied petroleum gas need not comply with the bottom loading provisions of Sections 5.1, 5.2 or 5.7, provided the operator complies with the emission limit of Section 5.1, 5.2 and the provisions of Section 5.6.

5.9 Leak Inspection Requirements

5.9.1 The operator of an organic liquid transfer facility shall inspect the vapor collection system, the vapor disposal system, and each transfer rack handling organic liquids for leaks during transfer at least once every calendar quarter using the test method prescribed in Section 6.3.8.

5.9.2 A floating roof container that meets the applicable control requirements of Section 5.0 of Rule 4623 (Storage of Organic Liquids) shall be considered not leaking for the purposes of this section.

5.9.3 All equipment that are found leaking shall be repaired or replaced within 72 hours. If the leaking component cannot be repaired or replaced within 72 hours, the component shall be taken out of service until such time the component is repaired or replaced. The repaired or replacement equipment shall be reinspected the first time the equipment is in operation after the repair or replacement.

Table 3 Repair Time Periods	
Type of Leak	Repair Time Period
Liquid Leak	72 hours
Gas Leak	72 hours

5.9.4 Until June 30, 2024,~~A~~an operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually provided no leaks were found during the inspections required under provisions of Sections 5.9.1 and 5.9.2 during five consecutive quarterly inspections. Upon identification of any leak during an annual inspection the frequency would revert back to quarterly and the operator shall contact the APCO in writing within 14 days.

5.9.5 After June 30, 2024, an operator is in violation if exceeding the allowable number of leaks during a District inspection as defined in Table 4 and 5.9.5.1.

Table 4 Number of Allowable Leaks after June 30, 2024	
Minor leaks	2.0% of number inspected
Major leaks	0

*The maximum number of leaks in Table 4 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of

leaks are calculated from the total number of components inspected during the specified inspection period. Leaks counted towards the allowable leaks in Table 4 are still subject to the repair requirements of section 5.9.3.

5.9.5.1 Failure to repair leaks within the timeframes specified in Table 3.

5.9.6 Except for inaccessible components and unsafe to monitor components, owners or operators shall audio-visually inspect (by hearing and by sight) all hatches, pressure-relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours; and,

5.9.6.1 Owners or operators shall audio-visually inspect all pipes for leaks or indications of leaks at least once every 12 months.

5.9.7 Any audio-visual inspection specified in Section 5.9.6 that indicates a leak shall be tested using US EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance with the repair timeframes specified in Section 5.9.3.

5.10 Maintenance Requirements

5.10.1 Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag.

5.10.2 The tag shall remain affixed to the component until all the conditions specified in Sections 5.10.2.1 through 5.10.2.3 have been met.

5.10.2.1 The leaking component has been successfully repaired or replaced; and,

5.10.2.2 The component has been re-inspected using the test method in Section 6.3.8; and

5.10.2.3 The component is found to be in compliance with the requirements of this rule.

5.10.3 The tag shall include the following information:

5.10.3.1 Date and time of leak detection; and

5.10.3.2 Date and time of leak measurement; and

5.10.3.3 For gaseous leaks, indicate the leak concentration in ppmv; and

5.10.3.4 For liquid leaks, the dripping rate of the liquid.

6.0 Administrative Requirements

6.1 Recordkeeping

6.1.1 An operator claiming exemption under Section 4.1 shall keep records of daily liquid throughput.

6.1.2 An operator claiming exemption under Section 4.3~~3~~2 of this rule shall maintain accurate daily records of liquid TVP.

6.1.2.1 Liquid TVP shall be determined using Appendix A or the applicable test method in Section 6.3.

6.1.2.2 The TVP shall be determined whenever there is a change in the type of liquid being transferred.

6.1.2.3 An operator may use a material safety data sheet (MSDS) in place of TVP testing if the transferred organic liquid is not crude oil or a petroleum distillate.

6.1.3 An operator subject to any part of Section 5.0 shall keep records of daily liquid throughput and the results of any required leak inspections.

6.1.4 Records required under Sections 6.1.1, 6.1.2, 6.1.3 shall be retained for a minimum of five years and shall be made readily available to the APCO, ARB, ~~or~~ and EPA during normal business hours and submitted upon request to the APCO, ARB, or EPA.

6.1.5 By July 1, 2008, operators of vacuum trucks claiming exemption under Section 4.5 shall submit to the District records covering 12 consecutive months of operation. The records shall indicate all of the following:

6.1.5.1 The number of vacuum trucks in operation;

6.1.5.2 The capacity of each vacuum truck storage container;

6.1.5.3 The average monthly throughput per vehicle;

6.1.5.4 The type of organic liquid transferred; and

6.1.5.5 The VOC capture and control equipment utilized.

6.1.6 Inspection Log

The operator shall maintain an inspection log containing, at a minimum, all of the following information:

6.1.6.1 Total number of components inspected, and total number and percentage of leaking components found during inspection.

6.1.6.2 Location, type, name or description of each leaking component and description of any unit where the leaking component is found.

6.1.6.3 Date of leak detection and method of leak detection.

6.1.6.4 For gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record the volume.

6.1.6.5 Date of repair, replacement, or removal from operation of leaking components.

6.1.6.6 After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv.

6.1.6.7 Inspector's name, business mailing address, and business telephone number.

6.1.6.8 The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.

6.1.6.9 Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.

6.1.6.10 Copies of all records required by Section 6.1 of this rule shall be retained for a minimum of five (5) years after the date of an entry, and the records shall be made available to the APCO, ARB, and US EPA upon request.

6.2 Compliance Testing

6.2.1 By July 20, 2009, the operator of any Class 1 or Class 2 organic liquid transfer facility shall perform an initial source test of the VOC emission control system in accordance with the method prescribed in Section 6.3.2 to determine compliance with Section 5.1 and 5.2, as applicable.

6.2.1.1 Facilities in existence prior to December 20, 2007, that have performed the test specified in Section 6.3.2 within the 60 month period preceding December 20, 2007, need not perform an initial source test.

6.2.1.2 The source testing requirements of Section 6.2.1 shall not apply to any Class 1 or Class 2 organic liquid transfer facility equipped with a closed VOC control system.

6.2.1.3 The source testing requirements of Section 6.2.1 shall not apply to any Class 1 or Class 2 organic liquid transfer facility controlling VOC by routing vapors to:

6.2.1.3.1 A fixed roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or

6.2.1.3.2 A floating roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or

6.2.1.3.3 A pressure vessel equipped with an APCO-approved vapor recovery system that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids).

6.2.2 The operator of any Class 1 or Class 2 organic liquid transfer facility shall perform the source test specified in Section 6.3.2 once every 60 months, but no more than 30 days before or after initial source test anniversary date.

6.3 Test Methods

6.3.1 Analysis of halogenated exempt compounds shall be by ARB Method 432.

6.3.2 Compliance with Sections 5.1 and 5.2 shall be determined using 40 CFR 60.503 "Test Methods and Procedures" and EPA Methods 2A, 2B, 25A and 25B and ARB Method 422, or ARB Test Procedure TP-203.1.

6.3.3 The TVP of any organic liquid shall be determined by measuring the Reid Vapor Pressure (RVP) using ASTM D 323 (Test Method for Vapor Pressure for Petroleum Products), and converting the RVP to TVP at the storage container's maximum organic liquid storage temperature. The conversion of RVP to TVP shall be done in accordance with the procedures in Appendix B. Appendix B is an excerpt from the oil and gas section of "ARB Technical Guidance Document to the Criteria and Guidelines Regulation for AB 2588", dated August 1989.

6.3.4 As an alternative to using ASTM D 323, the TVP of crude oil with an API gravity range of greater than 26 degrees up to 30 degrees may be determined by using other equivalent test methods approved by APCO and EPA.

6.3.5 The latest version of the Lawrence Berkeley National Laboratory "Test Method for Vapor Pressure of Reactive Organic Compounds in Heavy Crude Oil Using Gas Chromatograph", as approved by ARB and EPA, shall be used to determine the TVP of crude oil with an API gravity of 26 degrees or less, or for any API gravity that is specified in this test method.

6.3.6 An operator may use the information in Appendix A to determine the TVP of the stored organic liquid in a tank provided the storage temperature listed in Appendix A is not exceeded at any time.

6.3.7 The API gravity of crude oil or petroleum distillate shall be determined using ASTM Method D 287 (Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)). Sampling for API gravity shall be performed in accordance with ASTM Method D 4057 (Standard Practices for Manual Sampling of Petroleum and Petroleum Products).

6.3.8 Compliance with facility leaks as defined in Section 3.0 shall be determined using a portable hydrocarbon detection instrument in accordance with EPA Method 21.

6.3.8.1 <u>After June 30, 2024, All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 3.</u>

6.3.9 An alternative test method may be used if the alternative is approved in writing by the APCO and EPA.

6.4 Version of Test Methods

All ASTM test methods referenced in Section 6.0 are the most recently EPA-approved version that appears in the CFR as Materials Approved for Incorporation by Reference.

7.0 Compliance Schedule

~~7.1 Operators of transfer facility subject to this rule on or before December 20, 2007, shall be in full compliance with all applicable rule requirements on and after December 20, 2008, unless otherwise specified in the rule.~~

~~7.2 The owner or operator of any transfer facility which is subject to the requirements of this rule and which was installed or constructed after December 20, 2007, shall be in full compliance with the requirements of this rule upon initial operation.~~

7.~~3~~1 Any organic liquid transfer facility that is exempt pursuant to Section 4.1, 4.2, and 4.3 that becomes subject to the requirements of this rule through loss of exemption shall not be operated until such time that it is in full compliance with the requirements of this rule.

Appendix A

STORAGE TEMPERATURE VERSUS VAPOR PRESSURE

ORGANIC LIQUID	Reference Properties		Maximum Temp °F Not to Exceed
	Gravity °API	IBP °F	1.5 (psia)
Middle Distillates			
Kerosene	42.5	350	250
Diesel	36.4	372	290
Gas Oil	26.2	390	310
Stove Oil	23	421	340
Jet Fuels			
JP-1	43.1	330	230
JP-3	54.7	110	25
JP-4	51.5	150	68
JP-5	39.6	355	260
JP-7	44-50	360	260
Fuel Oil			
No. 1	42.5	350	250
No. 2	36.4	372	290
No. 3	26.2	390	310
No. 4	23	421	340
No. 5	19.9	560	465
Residual	19.27	---	---
No. 6	16.2	625	---
Asphalts			
60-100 pen.	---	---	550
120-150 pen.	---	---	500
200-300 pen.	---	---	420

IBP = Initial Boiling Point

Appendix B

California Air Resources Board Technical Guidance
to the Criteria and Guidelines Regulation for AB 2588
(Partial Excerpt from pages 102, 103 and 104)

True Vapor Pressure (TVP)

RVP is the absolute pressure of volatile crude oil and nonviscous petroleum liquids. Numerically, the relationship between TVP, RVP and temperature can be expressed by the following equation:

$$TVP = (RVP)\, e^{[Co(IRTEMP - ITEMP)]}$$

Where: C_o = Constant dependent upon the value of RVP
ITEMP = $(1/559.69^oR)$
IRTEMP = $(1/(T_s + 459.69^oR))$
T_s = Temperature of the stored fluid in ^oF

The value of the constant term C_o depends upon the given value of RVP.

Values of C_o for different RVP numbers are tabulated in Table C-3. It should be noted, however, that an error was discovered in the API nomograph calculated values of TVP so that the RVP was not equal to TVP at 100°F as was expected given the general definition of RVP. Using linear regression techniques, correction factors (C_F) were developed and should be added to the calculated values of TVP in order to obtain reasonable TVP numbers. The relationship between the three values is given as follows:

Corrected TVP = Calculated TVP + C_F

The correction factor was found to be dependent upon RVP according to the following equations:

If RVP < 3,

$C_F = (0.04) \times (RVP) + 0.1$

If RVP > 3,

$C_F = e^{[(2.3452061 \log (RVP)) - 4.132622]}$

Appendix B (Continued)

Table C-3 VALUES OF C_o FOR DIFFERENT RVP NUMBERS

RVP	C_o
0<RVP<2	-6622.5
2<RVP<3	-6439.2
RVP = 3	-6255.9
3<RVP<4	-6212.1
RVP = 4	-6169.2
4<RVP<5	-6177.9
RVP = 5	-6186.5
5<RVP<6	-6220.4
RVP = 6	-6254.3
6<RVP<7	-6182.1
RVP = 7	-6109.8
7<RVP<8	-6238.9
RVP = 8	-6367.9
8<RVP<9	-6477.5
RVP = 9	-6587.9
9<RVP<10	-6910.5
RVP = 10	-7234.0
10<RVP<15	-8178.0
RVP > 15	-9123.2

San Joaquin Valley Unified Air Pollution Control District
Meeting of the Governing Board
June 15, 2023

ADOPT PROPOSED AMENDMENTS TO DISTRICT LEAK DETECTION AND REPAIR RULES 4401, 4409, 4455, 4623, AND 4624

Attachment C:

Final Draft Staff Report with Appendices for Proposed Amendments to Rules 4401, 4409, 4455, 4623, and 4624

(190 PAGES)

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

FINAL DRAFT STAFF REPORT

Proposed Amendments to Rule 4401 (Steam-Enhanced Crude Oil Production Wells)

Proposed Amendments to Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities)

Proposed Amendments to Rule 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants)

Proposed Amendments to Rule 4623 (Storage of Organic Liquids)

Proposed Amendments to Rule 4624 (Transfer of Organic Liquid)

June 15, 2023

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San Joaquin Valley
UNIFIED AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

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I. SUMMARY

The San Joaquin Valley Unified Air Pollution Control District (District) is committed to protecting public health for all residents in the San Joaquin Valley (Valley) through efforts to meet health-based state and federal ambient air quality standards with efficient, effective, and entrepreneurial air quality management strategies. In response to the latest federal mandates and to improve quality of life for Valley residents, the District has developed and implemented multiple generations of rules on various sources of air pollution. Valley businesses are currently subject to the most stringent air quality regulations in the nation. Since 1992, the District has adopted over 650 rules to implement an aggressive on-going control strategy to reduce emissions in the Valley, resulting in air quality benefits throughout the Valley. Similarly, the California Air Resources Board (CARB) has adopted increasingly stringent regulations for mobile sources. Together, these efforts represent the nation's toughest suite of air pollution emissions controls and have greatly contributed to reduced ozone and particulate matter concentrations across the Valley.

The proposed amendments to District Rules 4401 (Steam-Enhanced Crude Oil Production Wells), 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities), 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants), 4623 (Storage of Organic Liquids), and 4624 (Transfer of Organic Liquids) are primarily driven by a need to address requirements implementing Best Available Retrofit Control Technology (BARCT) pursuant to Assembly Bill 617 (AB 617). However, during the initial rule amendment process, the U.S. Environmental Protection Agency (EPA) published a Technical Support Document (TSD) identifying deficiencies in CARB's state regulation, California's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities,[1] also known as the California Oil and Gas Regulation (COGR). In addition to the deficiencies outlined in COGR, EPA's TSD also outlined deficiencies in multiple air districts' rules, including District Rules 4401, and 4623, which the District is fully addressing in this proposal. Finally, the District also made commitments in the District's *2022 Plan for the 2015 8-Hour Ozone Standard* (*2022 Ozone Plan*) to amend the proposed rules. The proposed rule amendments address BARCT and EPA Control Techniques Guidelines (CTG), including establishing more stringent leak detection and repair (LDAR) requirements for volatile organic compound (VOC) emissions from various types of components associated with the production of oil and gas and associated control equipment. Additionally, in order to provide better service to stakeholders and affected industry, the proposed rule amendments simplify and clarify existing rule standards and language.

[1] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, October 2018, https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf

The District will continue to evaluate this source category for additional potential amendments as we monitor future state (COGR), federal New Source Performance Standards (NSPS), CTG requirements, and other district regulatory amendments.

A. Reasons for Rule Development

Under Assembly Bill 617 (AB 617)[2], air districts in nonattainment areas are required to adopt an expedited schedule to implement the most current Best Available Retrofit Control Technology (BARCT) limits on industrial sources that are subject to the State Cap-and-Trade program. Existing stationary sources in nonattainment areas such as the Valley have been subject to BARCT requirements since the 1980s. However, some nonattainment areas with market-based criteria pollutant reduction programs were not required to apply BARCT to facilities complying with those market-based programs. Although AB 617 legislation does not specifically define BARCT, California Health and Safety Code (CH&SC) Section 40406[3] defines BARCT as follows:

> *"BARCT is an air emission limit that applies to existing sources and is the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts by each class or category of source."*

AB 617 further recognizes that "existing law authorizes a district to establish its own best available control technology requirement based upon the consideration of specified factors."

As part of the BARCT Rule Evaluation, the District identified more stringent LDAR leak thresholds, repair times, and frequency of inspection in other district, state, and federal regulations. Therefore, the District conducted a broader rule making effort, including a comprehensive technical analysis, in-depth review of local, state, and federal regulations, cost-effectiveness analysis, and a robust public process.

While the District has required the implementation of stringent LDAR programs that have resulted in significant reductions in VOC emissions, the District began this rule development process in 2020 to explore opportunities to enhance the stringency of the rules and ensure the continued implementation of BARCT by determining the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts of the source categories subject to District LDAR Rules.

In addition, EPA established Reasonably Available Control Technology (RACT) requirements for the oil and natural gas industry subject to the agency's 2016 Control

[2] AB 617, Garcia, C., Chapter 136, Statutes of 2017. Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB617

[3] Health and Safety Code, Division 26, Part 3, Chapter 5.5, Article 1, Retrieved from https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=HSC&sectionNum=40406.

Techniques Guidelines (CTG) for the Oil and Gas Industry.[4] To address the 2016 CTG, CARB adopted COGR[1], which establishes methane emission standards for crude oil and natural gas sources. COGR defaults to local air district rules for some categories of emission sources.

On September 30, 2022, EPA finalized in the Federal Register a limited approval, limited disapproval of COGR[5]. The Technical Support Document (TSD)[6] from this action references the 2016 CTG as containing EPA's RACT recommendations for reducing VOC emissions from special equipment and processes used in the oil and natural gas industry. As part of this action, EPA cited deficiencies in COGR and a number of local California air district rules (the District, South Coast AQMD, Sacramento Metropolitan AQMD, Ventura County APCD, Yolo-Solano AQMD, and Feather River AQMD). For the District, EPA identified Rules 4401 and 4623 as deficient in meeting RACT requirements as outlined in the 2016 CTG. As such, this rulemaking action also addresses the deficiencies identified by EPA.

Based on a comprehensive technical analysis, in-depth review of local, state, and federal regulations, and a robust public process, the District is proposing several amendments to Rules 4401, 4409, 4455, 4623, and 4624, which will reduce VOC emissions in the Valley. The proposed rule amendments will address BARCT requirements pursuant to AB 617, address RACT requirements pursuant to EPA's 2016 CTG, and satisfy commitments in the *2022 Ozone Plan*.

B. Health Benefits of Proposed Amendments

The proposed amendments reduce fugitive VOC emissions from applicable sources, a contributor in the formation of ozone, from oil and natural gas sources as well as petroleum refining. Additionally, fugitive emissions may also contain hazardous air pollutants, such as benzene and other carcinogens known to cause adverse health impacts. Exposure to ozone has been linked to a variety of health issues, including chest pain, coughing, throat irritation, congestion, reduced lung function, and inflammation of the lining of the lungs. Repeated exposure to elevated concentrations of ozone may also permanently scar lung tissue. People with asthma, children, older adults, people active outdoors, and outdoor workers are at higher risk from exposure to high levels of ozone, and studies have linked rising hospital admissions and emergency room visits to higher ozone levels. The District has worked with CARB and EPA to reduce ground level ozone concentrations through the implementation of

[4] Control Techniques Guidelines for the Oil and Natural Gas Industry, October 20, 2016 https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/2016-control-techniques-guidelines-oil-and

[5] EPA. *Limited Approval, Limited Disapproval, of California Air Plan Revisions; California Air Resources Board, Final Rule*. (30 September, 2022) Retrieved from: https://www.govinfo.gov/content/pkg/FR-2022-09-30/pdf/2022-20870.pdf

[6] EPA. *Technical Support Document for EPA's Rulemaking for the California State Implementation Plan.* April 2022. Retrieved from: https://www.regulations.gov/document/EPA-R09-OAR-2022-0416-0002

comprehensive emission reduction regulations while also incentivizing the implementation of low emission mobile source technologies through a variety of grant programs. Further reducing NOx and VOC emissions, the primary precursors to ozone formation, contributes to additional and significant public health and economic benefits in the San Joaquin Valley.

C. Rule Development Process

As part of the rule development process, the District conducted public workshops to present and discuss potential amendments to the District's LDAR Rules (Rules 4401, 4409, 4455, 4623, and 4624). The District shared information about public meetings with members of the public, source operators, consultants, vendors and manufacturers of control technologies, trade associations, and AB 617 community steering committee members. The District conducted public meetings/workshops in July 2020, December 2020, April 2021, October 2021, March 2022, October 2022, and April 2023. The District provided updates throughout the rule development process and BARCT evaluation to stakeholders.

At the rule development public workshops, the District presented the objectives of the proposed rulemaking project. The District published draft rules for public review on March 10, 2022, and April 17, 2023, to provide opportunity for public comment on draft amendments. Throughout the rule development process, District staff solicited information from affected source operators, consultants, and trade associations on the feasibility and compliance costs to assist the District in developing amendments to the LDAR Rules. The District incorporated comments received from the public, affected sources, and interested parties during the public outreach and workshop process into the rule amendments as appropriate.

Pursuant to state law, the District is required to perform a socioeconomic impact analysis prior to adoption, amendment, or repeal of a rule that has significant air quality benefits or that will strengthen emission limitations. As part of the District's socioeconomic analysis process, the District hired a socioeconomic consultant to prepare a socioeconomic impact report. The results of the socioeconomic analysis are included in Appendix D.

The proposed rule amendments were published for 30-day public review and comment on May 16, 2023, prior to the public hearing to consider the adoption of the proposed amendments by the District Governing Board. The public hearing is scheduled on June 15, 2023.

II. DISCUSSION

A. Current Rules

Over the years, the District has adopted numerous generations of rules and rule amendments for components found within the oil and gas sector, including petroleum refineries. The adoption and amendments of these rules has significantly reduced VOC emissions from this source category.

The summaries below provide additional information on the current version of each rule.

Rule 4401 – Steam-Enhanced Crude Oil Production Well Vents

The District adopted Rule 4401 on April 11, 1991. The District subsequently amended Rule 4401 five times, with the most recent amendments occurring in June 2011. EPA finalized approval of the 2011 amendments to Rule 4401 on November 16, 2011 and deemed this Rule as being as stringent as established RACT requirements.[7] EPA further confirmed this RACT determination when they finalized a partial approval/partial disapproval of the *2009 RACT SIP* on January 10, 2012.[8]

Rule 4401 applies to all steam-enhanced crude oil production wells and any associated VOC collection and control systems. The purpose of this Rule is to limit VOC emissions from these sources, particularly from casing vents. VOC emissions can also occur from components serving both open and closed casing systems.

Rule 4409 – Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

The District adopted Rule 4409 on April 20, 2005. EPA finalized approval of the 2005 adoption of Rule 4409 on March 23, 2006, and deemed this Rule at least as stringent as established RACT requirements.[9] EPA further confirmed this RACT determination when they finalized a partial approval/partial disapproval of the *2009 RACT SIP* on January 10, 2012.[8]

Rule 4409 applies to components containing or contacting VOC streams at light crude oil production facilities, natural gas production facilities, and natural gas processing

[7] EPA. *Revisions to the California State Implementation Plan, San Joaquin Valley Unified Air Pollution Control District; Final Rule*. 76 Fed. Reg. 221, pp. 70886 – 70887. (2011, November 16). (to be codified at 40 CFR Part 52). Retrieved from http://www.gpo.gov/fdsys/pkg/FR-2011-11-16/pdf/2011-29466.pdf

[8] EPA. *Partial Approval and Partial Disapproval of Air Quality Implementation Plans; California; San Joaquin Valley; Reasonably Available Control Technology for Ozone; Final Rule*. 77 Fed. Reg. 6, pp 1417 – 1427. (2012, January 10). (to be codified at 40 CFR Part 52). Retrieved from http://www.gpo.gov/fdsys/pkg/FR-2012-01-10/pdf/2012-139.pdf

[9] EPA. *Revisions to the California State Implementation Plan, San Joaquin Valley Unified Air Pollution Control District; Final Rule.* 77 Fed. Reg.56, pp 14652 - 14654 (2006, March 23). (to be codified at 40 CFR Part 52). Retrieved from https://www.govinfo.gov/content/pkg/FR-2006-03-23/pdf/06-2814.pdf

facilities. The purpose of this Rule is to limit VOC emissions from components at these facilities, including, but not limited to, valves, fittings, threaded connections, pumps, compressors, pressure relief devices, pipes, polished rod stuffing boxes, flanges, process drains, sealing mechanisms, hatches, sight-glasses, meters, or seal fluid systems in VOC service.

VOC emissions can occur from oil and gas flowing through the various components containing or contacting VOC streams. Rule 4409 contains a schedule that specifies the number of allowable component leaks based on the number and type of components inspected.

Rule 4455 – Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

The District adopted Rule 4455 on April 20, 2005. EPA finalized approval of the 2005 adoption of Rule 4455 on March 23, 2006, and deemed this Rule at least as stringent as established RACT requirements.[10] EPA further confirmed this RACT determination when they finalized a partial approval/partial disapproval of the *2009 RACT SIP* on January 10, 2012, and again deemed this Rule at least as stringent as established RACT requirements.[11]

Rule 4455 applies to components containing or contacting VOC streams at petroleum refineries, gas liquid processing facilities, and chemical facilities. The purpose of this Rule is to limit VOC emissions from components at these facilities, including, but not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, flange, process drain, sealing mechanism, hatch, sight-glass, meter or seal fluid system in VOC service.

VOC emissions can occur from oil and gas flowing through the various components containing or contacting VOC streams.

Rule 4623 – Storage of Organic Liquids

The District adopted Rule 4623 on April 11, 1991. The District subsequently amended Rule 4623 four times, with the most recent amendments occurring in May of 2005. EPA finalized approval of the 2005 amendments to Rule 4623 on September 13, 2005, and

[10] EPA. *Revisions to the California State Implementation Plan, San Joaquin Valley Unified Air Pollution Control District; Final Rule*. 71 Fed. Reg. 56, pp. 14652 – 14654. (2006, March 23). (to be codified at 40 CFR Part 52). Retrieved from http://www.gpo.gov/fdsys/pkg/FR-2006-03-23/pdf/06-2814.pdf

[11] EPA. *Partial Approval and Partial Disapproval of Air Quality Implementation Plans; California; San Joaquin Valley; Reasonably Available Control Technology for Ozone; Final Rule*. 77 Fed. Reg. 6, pp 1417 – 1427. (2012, January 10). (to be codified at 40 CFR Part 52). Retrieved from http://www.gpo.gov/fdsys/pkg/FR-2012-01-10/pdf/2012-139.pdf

deemed this Rule at least as stringent as established RACT requirements.[12] EPA further confirmed this RACT determination when they finalized of the approval of the *2014 RACT SIP* on August 17, 2018.[13]

Rule 4623 applies to tanks that store organic liquids and have a capacity of at least 1,100 gallons. The tank size and true vapor pressure (TVP) of the stored organic liquid determines the tank VOC control requirements.

VOC emissions from the storage of organic liquids occur due to evaporative loss of liquid resulting from changes in liquid level during both the filling and emptying processes (working loss). Additional VOC emissions occur when there are changes in storage temperature due to fluctuations in ambient temperature or when heating the tanks prior to shipping (standing or breathing loss). Rule 4623 reduces VOC emissions by requiring proper maintenance of tanks, use of Pressure Vacuum Relief Valves and/or vapor control systems for various tanks.

Rule 4624 – Transfer of Organic Liquid

The District adopted Rule 4624 on April 11, 1991. The District subsequently amended Rule 4624 four times, with the most recent amendments occurring in December of 2007. EPA finalized approval of the 2007 amendments to Rule 4624 on October 15, 2009, and deemed this Rule at least as stringent as established RACT requirements.[14] EPA further confirmed this RACT determination when they finalized approval of the *2014 RACT SIP* on August 17, 2018.[15]

Rule 4624 applies to organic liquid transfer facilities. The purpose of this Rule is to limit VOC emissions associated with the transfer of organic liquids from both loading and unloading racks with stationary organic liquid pumps.

Facilities transferring 20,000 gallons or more per day of organic liquid must comply with a VOC emission limit of 0.08 lb per 1,000 gallons, use bottom loading tanker trailers,

[12] EPA. *Revisions to the California State Implementation Plan, San Joaquin Valley Unified Air Pollution Control District; Final Rule*. 70 Fed. Reg. 176, pp. 53936 – 53938. (2005, September 13). (to be codified at 40 CFR Part 52). Retrieved from https://www.govinfo.gov/content/pkg/FR-2005-09-13/pdf/05-18019.pdf

[13] EPA. *Air Plan Approval; California; San Joaquin Valley Unified Air Pollution Control District; Reasonably Available Control Technology Demonstration; Final Rule*. 83 Fed. Reg.160, pp 41006 – 41009. (2018, August 17). (to be codified at 40 CFR Part 52). Retrieved from https://www.govinfo.gov/content/pkg/FR-2018-08-17/pdf/2018-17714.pdf

[14] EPA. *Revisions to the California State Implementation Plan, San Joaquin Valley Unified Air Pollution Control District; Final Rule*. 74 Fed. Reg. 198, pp. 52894 – 52895. (2009, October 15). (to be codified at 40 CFR Part 52). Retrieved from https://www.govinfo.gov/content/pkg/FR-2009-10-15/pdf/E9-24687.pdf

[15] EPA. *Air Plan Approval; California; San Joaquin Valley Unified Air Pollution Control District; Reasonably Available Control Technology Demonstration; Final Rule*. 83 Fed. Reg.160, pp 41006 – 41009. (2018, August 17). (to be codified at 40 CFR Part 52). Retrieved from https://www.govinfo.gov/content/pkg/FR-2018-08-17/pdf/2018-17714.pdf

and route VOC vapors to a vapor collection and control system, a fixed roof container, a floating roof container, a pressure vessel, or other closed VOC emission control system. Facilities transferring less than 20,000 gallons but more than 4,000 gallons per day of organic liquid must capture at least 95 percent of VOC vapors displaced during loading, use bottom loading, and route VOC vapors to a vapor collection and control system, a fixed roof container, a floating roof container, a pressure vessel, or other closed VOC emission control system.

B. Amendments for BARCT and RACT

Analysis and Proposed Amendments to Address BARCT

Based on the District's recent AB 617 BARCT analysis, the District evaluated potential amendments to the leak detection and repair requirements for District Rules 4401, 4409, 4455, 4623, and 4624. As part of this analysis, the District reviewed leak thresholds and repair timeframes from the following air district rules, and state and federal regulations and guidelines:

- Bay Area Air Quality Management District (BAAQMD)
- California Oil and Gas Regulation (COGR)
- EPA 2016 Control Technology Guideline for the Oil and Gas Industry (EPA-453/B-16-001)
- EPA New Source Performance Standards (NSPS)
- Santa Barbara County Air Pollution Control District (SBCAPCD)
- South Coast Air Quality Management District (SCAQMD)
- Ventura County Air Pollution Control District (VCAPCD)

The District completed an in-depth review of local, state, and federal regulations, and found that the current VOC control technology requirements in Rules 4401, 4623, and 4624 meet or exceed BARCT levels of control; therefore, the District is proposing no changes to the VOC control requirements within these rules. Rules 4409 and 4455 only include LDAR requirements; however, facilities subject to these rules may have equipment subject to the control requirements of other District Rules, such as Rule 2201 (New and Modified Stationary Source Review), Rule 4311 (Flares), Rule 4623, and Rule 4624. The District will continue to monitor and evaluate other local air district rules, state and federal regulations and guidelines, to assess the future need to amend District Rules.

Analysis and Proposed Amendments to Address EPA 2016 CTG Deficiency

On September 30, 2022, EPA finalized in the Federal Register a limited approval, limited disapproval of COGR[5]. The TSD from this action references the 2016 CTG as containing EPA's RACT recommendations for reducing VOC emissions from special equipment and processes used in the oil and natural gas industry. As part of this action, EPA cited deficiencies in COGR and local air district rules, including District

Rules 4401, and 4623. EPA's limited disapproval addressed the following deficiencies in District Rule 4401 and 4623:

1. Current rules (4401 and 4409) have a minor leak threshold of 2,000 ppmv for Rule 4401 and 1,000 ppmv for Rule 4409, while the 2016 CTG recommends 500 ppmv.
2. Current rule (4401) requires annual inspections while CTG recommends more frequent monitoring.
3. Current rules (4401 and 4409) exempt one-half inch and smaller stainless steel tube fittings used to supply natural gas to equipment or instrumentation from continuous monitoring, while the CTG does not provide for this exemption.
4. Unclear whether current rule (4623) requires vapor control systems for storage tanks with Potential to Emit (PTE) greater than 6 tons per year of VOC or actual emissions greater than or equal to 4 tons per year.

Addressing EPA's TSD for Rule 4401

For components at well sites, the 2016 CTG recommends conducting monthly inspections of valves and pumps using EPA Reference Method 21 at a 500 ppmv leak threshold until the components are leak free for two consecutive months, then inspections can transition to quarterly inspections at 500 ppmv. For all other components, inspections must be conducted semi-annually. The 2016 CTG suggests that monthly inspections at 500 ppmv achieve an emission reduction of 92 percent, while semi-annual inspection for all other components achieve an emission reduction of 74 percent. In 2018, CARB staff determined in their Staff Report[16] the overall emission reduction for monthly inspection of valves and semi-annual inspection of all other components achieves 80 percent reduction, using a weighted average of the monthly and annual inspection based on the distribution of valves and connectors included in the 2016 CTG's model natural gas processing plant.[17]

The District is proposing quarterly inspections using EPA Reference Method 21 at 500 ppmv for all components subject to Rule 4401. Emission reductions from EPA Reference Method 21 monitoring programs are estimated for a variety of monitoring frequencies and leak thresholds using the EPA Protocol for Equipment Leak Emission Estimates[18], consistent with the 2016 CTG. Using this protocol, quarterly monitoring at a leak threshold of 500 ppmv achieves 89 percent emission reductions overall. By

[16] CARB. *Staff Report: Proposed Submission of California's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities Into the California State Implementation Plan.* (September 21, 2018). Retrieved from: https://ww2.arb.ca.gov/sites/default/files/2020-04/O_G%20CTG%20-%20Staff%20Report.pdf

[17] EPA. *Control Techniques Guidelines for the Oil and Natural Gas Industry*. (2016). Retrieved from: https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf

[18] EPA. *Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)*. Research Triangle Park, NC: Office of Air Quality Planning and Standards. (1995). Retrieved from: https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

contrast, the 2016 CTG as noted achieves 80 percent reductions with its combination of monthly and semi-annual inspections at 500 ppmv as recommended for components located at well sites.

The District's proposal of quarterly inspection of all components at 500 ppmv provides greater emission reduction than the monthly monitoring of valves and pumps. Following the EPA protocol, increasing the frequency of monitoring to quarterly for all components results in greater emission reductions compared to increasing the monitoring frequency for certain components. Therefore, the District is proposing quarterly monitoring at 500 ppmv for all components.

Addressing EPA's TSD for Rule 4623

Current District Rule 4623 requires vapor control systems based on size of tank and TVP of the stored liquid. EPA's CTG requires a vapor control system based on if the PTE of storage tank equals or exceeds six (6) tons per year or if the actual VOC emissions exceed four (4) tons per year. The District believes that based on the current requirements of Rule 4623, all tanks that have a PTE greater than 6 tons per year or actual emissions greater than 4 tons per year more than likely already have installed vapor control systems. However, to ensure that there is no deficiency in meeting the CTG requirements, the District is proposing to add the following language to District Rule 4623 in the applicability and tank requirements sections:

> Section 2.0 Applicability
> *This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held, or stored, and any tank used in crude oil or natural gas production operations with a potential to emit six (6) tons of VOC or greater per year.*
>
> Section 5.0 Requirements
> *If a tank has the Potential to Emit greater than or equal to six (6) tons per year of VOC and actual emissions are greater than or equal to four (4) tons per year using a generally accepted model or calculation methodology, operator must install a vapor control system meeting the specifications described in Sections 5.3, 5.4, 5.5 or 5.6.*

Addressing EPA's Comments for Rule 4409

Although not initially cited in the TSD, EPA provided comments to the District during the rulemaking stating that the CTG is more stringent for equipment at natural gas processing facilities. The 2016 CTG recommends conducting monthly inspections of valves and pumps using EPA Reference Method 21 at a 500 ppmv leak threshold until the components are leak free for two consecutive months, then inspections can transition to quarterly inspections at 500 ppmv. For all other components at natural gas processing plants, inspections must be conducted annually. The 2016 CTG states that monthly inspections at 500 ppmv achieve an emission reduction of 92 percent, while annual inspection for all other components achieve an emission reduction of 68

percent.[19] In 2018, CARB staff determined that the monthly inspection of valves and annual inspections of all other components achieves a 74 percent reduction in emissions, using a weighted average of the monthly and annual inspection based on the distribution of valves and connectors included in the 2016 CTG's model natural gas processing plant.[20]

The District is proposing quarterly inspections using EPA Reference Method 21 at 500 ppmv for all components subject to Rule 4409. Emission reductions from EPA Reference Method 21 monitoring programs are estimated for a variety of monitoring frequencies and leak thresholds using the EPA Protocol for Equipment Leak Emission Estimates[21], consistent with the 2016 CTG. Using this protocol, quarterly monitoring at a leak threshold of 500 ppmv achieves 89 percent emission reductions overall. By contrast, the 2016 CTG as noted achieves 74 percent reductions with its combination of monthly and annual inspections at 500 ppmv as recommended for components located at natural gas processing facilities.

The District's proposal of quarterly inspection of all components at 500 ppmv outweighs the impact of monthly monitoring of valves and pumps. Using the EPA protocol, increasing the frequency of monitoring to quarterly for all components at 500 ppmv results in higher emission reductions than increasing the monitoring frequency for certain components. Therefore, the District is proposing quarterly monitoring at 500 ppmv for all components.

In their final ruling published in the Federal Register[4], EPA also commented on the potential deficiency for heavy crude oil with an API gravity of less than 20. The disapproval outlines the lack of analysis provided to EPA that demonstrate controls are not cost effective, or that emissions are minimal, which would satisfy RACT requirements. CARB has conducted and submitted to EPA an analysis demonstrating that no deficiency exists in their 2023 Initial Statement of Reasoning.[22] The analysis included the approximate cost to eliminate their heavy oil exemption. In the analysis, CARB projects an increased cost of $26,023,588 per year. The emission reductions are projected at 299.8 metric tons per year of methane, which is equivalent to 0.148 tons of

[19] EPA. *Control Techniques Guidelines for the Oil and Natural Gas Industry*. (2016). Retrieved from: https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf
[20] EPA. *Control Techniques Guidelines for the Oil and Natural Gas Industry*. (2016). Retrieved from: https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf
[21] EPA. *Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)*. Research Triangle Park, NC: Office of Air Quality Planning and Standards. (1995). Retrieved from: https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf
[22] California Air Resources Board. Public Hearing to Consider the Proposed Amendments to the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2023/oilgas2023/isr.pdf

VOC per day.[23] CARB's analysis found that the emissions from heavy oil components are insignificant, and therefore no further District action is needed.

C. Proposed Amendments to Rules 4401, 4409, 4455, 4623, and 4624

The following sections detail the proposed amendments to rule language and requirements. For further information on how proposed limits were determined, see the District's Cost Analysis in Appendix C. Additionally, in an effort to simplify rule language and clarify existing requirements, the District is removing expired language in the rules. See the proposed rules for exact language.

Proposed Amendments to Rule 4401

In determining potential amendments to Rule 4401, the District considered the following rules and regulations:

- South Coast Air Quality Management District Rule (SCAQMD) 1148.1
- South Coast Air Quality Management District Rule (SCAQMD) 1173
- Ventura County Air Pollution Control District (VCAPCD) Rule 74.10
- Santa Barbara County Air Pollution Control District (SBCAPCD) Rule 331
- California Oil and Gas Regulation (COGR)
- EPA 2016 Control Technology Guideline for the Oil and Gas Industry (EPA-453/B-16-001)
- EPA New Source Performance Standard (NSPS) Subpart OOOO
- EPA NSPS Subpart OOOOa

Table 1 provides a comparison of the District's requirements to other local, State, and Federal regulations including the District's proposed leak standards.

[23] California Air Resources Board. Appendix B: Economic Analysis for Proposed Amendments to the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2023/oilgas2023/israppb.pdf

Table 1 – Comparison of District Rule 4401 to Similar Rules and Regulations

Rule 4401 – Steam-Enhanced Crude Oil Production Wells							
Current Leak Standard	**VCAPCD Rule 74.10**	**SBCAPCD Rule 331**	**SCAQMD Rule 1173**	**SCAQMD Rule 1148.1**	**CARB COGR**	**EPA NSPS Subpart OOOO and OOOOa**	**EPA 2016 CTG for the Oil and Gas Industry (EPA-453/B-16-001)**
Gas • Minor: 400 ppmv (PRDs) • Minor: 2,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • 100 ppmv (pump in heavy liquid service) • 200 ppmv (PRDs) • 500 ppmv in light crude service • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min.	**Gas** • 100 ppmv (any component in heavy liquid service) • 500 ppmv (any component in light liquid service)	• Limit: 1,000 ppmv	• Leak Limit: 500 ppmv • Leak Limit: 2,000 ppmv for pumps in light crude service • Leak Limit: 10,000 ppmv for pumps in heavy crude service	• Leak Limit: 500 ppmv (valves, compressors, PRDs) • Leak Limit: 2,000 ppmv (pumps)

Based on the above comparison, the District evaluated lowering the LDAR threshold minor leak gas category from 2,000 ppmv to three specific thresholds including 1,000 ppmv, 500 ppmv, and 100 ppmv. Based on the District's analyses and cost-effectiveness analysis shown in Appendix C, the District is proposing a 500 ppmv LDAR threshold, which meets or exceeds BARCT. The District is also proposing to increase the frequency of LDAR inspections required by an operator from annual to quarterly for all components.

Reducing the leak threshold to 500 ppmv also meets RACT recommendations established in the 2016 CTG. For equipment leaks, the 2016 CTG requires monthly inspections of valves and semi-annual inspections of connectors using EPA Reference Method 21 at 500 ppmv leak threshold. As discussed earlier, quarterly inspections of all components at 500 ppmv achieve more emissions reductions than the recommended 2016 CTG requirements.

Section 1.0 – Purpose

No changes proposed at this time.

Section 2.0 – Applicability

No changes proposed at this time.

Section 3.0 – Definitions

The District is proposing amendments to definitions to meet BARCT requirements, and comply with RACT deficiencies cited for Rule 4401 from the 2016 CTG. The District is proposing a revised minor leak definition to reflect the proposed LDAR threshold. The leak threshold is defined in Table 1 of the current rule as 2,000 ppmv for minor gas leaks. The District is establishing a lower LDAR threshold of 500 ppmv for minor gas leaks.

- 3.20 *Leak*: Updates to Table 1 contain new language to indicate that Table 1 is effective until June 30, 2024. The requirements of new Table 2 go into effect after June 30, 2024. Table 2 contains a new minor leak definition for components other than Pressure Relief Devices (PRD). The threshold for components other than PRD's will be 500 ppmv.

Table 1 – Gas Leak in ppmv as Methane until June 30, 2024		
Type of Component	Major Gas Leak	Minor Gas Leak
1. PRDs	Greater than 10,000	400 to 10,000
2. Components other than PRDs	Greater than 10,000	2,000 to 10,000

Table 2 – Gas Leak in ppmv as Methane after June 30, 2024		
Type of Component	Major Gas Leak	Minor Gas Leak
1. PRDs	Greater than 10,000 to 49,999	400 to 10,000
2. Components other than PRDs	Greater than 10,000 to 49,999	500 to 10,000

- 3.22 *Major Component*: Update to definition for consistency and clarity. The change to the definition is as follows:

  Major Component: *a pump five (5) brake horsepower or larger, any compressor, or any pressure relief ~~valve~~ device four (4) inches in diameter or larger.*

- 3.23 *Open-ended Line or Valve*: The District updated the definition of Open-ended Line for consistency across all the applicable rules as follows:

  Open-ended Line or Valve: *a line or valve, except for pressure relief device and process drains, having one side of the line or valve seat in contact with the process fluid and one side open to the atmosphere, either directly or through an open piping*.

- 3.25 *Optical Gas Imaging (OGI)*: The District added a definition to include OGI to Rule 4401. The new definition reads as follows:

  Optical Gas Imaging (OGI): *an instrument that makes emissions visible that may otherwise be invisible to the naked eye.*

- 3.28 *Pressure Relief Device (PRD)*: The District updated the definition of Pressure Relief Devices (PRD) to encompass the definition of a Pressure Relief Valve. This provides consistency across other District LDAR rules. The new language prompts the removal of existing definition 3.28, Pressure Relief Valve (PRV).

- 3.30 *Process System*: Update to the definition to account for the new regulating agency California Geologic Energy Management Division (CalGEM).

- 3.35 *Rig-up Operation*: The District added a new definition for "Rig-up Operation". Rig-up operations require special equipment that some facilities must contract from third parties. The circumstances and provisions are now included in Section 5.5.8 of Rule 4401 to account for Rig-up operations.

Section 4.0 – Exemptions

The District is proposing to remove exemption 4.6.4 from Rule 4401. Rule 4401 Section 4.6.4 exempts half inch or less stainless steel tube fittings from LDAR inspections, and leak requirements after their initial inspection. The removal of this exemption meets RACT recommendations as the exemption of these components is not found in the 2016 CTG. These components will now be subject to the leak standard, and inspection frequency of proposed Rule 4401.

The District is proposing to remove exemption 4.7 from Rule 4401. Rule 4401 Section 4.7 exempts components exclusively handling gas/vapor or liquid with a VOC content of 10 percent by weight or less from LDAR inspections. These components are already required to conduct LDAR inspections under COGR and with this exemption removed, these components will now be subject to Rule 4401.

Section 5.0 – Requirements

The District is proposing to increase the frequency of LDAR inspections from annual to quarterly. The District evaluated requirements in analogous rules, including VCAPCD Rule 74.10, SBCAPCD Rule 325, and COGR, which contain quarterly inspection requirements. Increasing the frequency of inspections will make Rule 4401 as stringent as other comparable rules and regulations.

- 5.2.2.4 Modification to the number of allowable leaks table is effective after June 30, 2024. The District determined that on average, a well has 32 components. To comply with the 2016 CTG recommendations of allowable leaks without a violation, the District is reducing the number of allowable leaks to zero if five wells or fewer are inspected. Additional language was added to highlight that all leaks are still subject to the leak repair timeframes. The current table 3 and the new table 4 are shown below:

Table 3 – Number of Allowable Leaks until June 30, 2024	
Number of Steam-Enhanced Crude Oil Production Wells Connected to a VOC Collection and Control System	Number of Allowable Leaks
1 to 25	3
26 to 50	6
51 to 100	8
101 to 250	10
251 to 500	15
More than 500	One (1) for each 20 wells tested with a minimum of 50 wells tested.

*Leaks counted toward the allowable leaks in Table 3 are still subject to component repair requirements of section 5.5.

Table 4 – Number of Allowable Leaks after June 30, 2024	
Number of Steam-Enhanced Crude Oil Production Wells Connected to a VOC Collection and Control System	Number of Allowable Leaks
1 to 5	0
6 to 25	3
26 to 50	6
51 to 100	8
101 to 250	10
251 to 500	15
More than 500	One (1) for each 20 wells tested with a minimum of 50 wells tested.

*Leaks counted toward the allowable leaks in Table 4 are still subject to component repair requirements of section 5.5.

- 5.4 Updates in this section and new subsection phase out Section 5.4.1 after June 30, 2024, and replace it with new Section 5.4.2. The action establishes quarterly inspections required for all components subject to Rule 4401 after June 30, 2024.

- 5.5.4 New Table 6 takes effect after June 30, 2024. The new table reduces the repair period for gas leaks greater than 50,000 ppmv, and major liquid leaks. Current Table 5 and new Table 6 are shown below:

Table 5 – Repair Period until June 30, 2024	
Type of Leak	**Repair Period in Calendar Days**
Gas Leaks	
Minor Gas Leak	14
Major Gas Leak less than or equal to 50,000 ppmv	5
Gas Leak greater than 50,000 ppmv	2
Liquid Leaks	
Minor Liquid Leak	3
Major Liquid Leak	2

Table 6 – Repair Period after June 30, 2024	
Type of Leak	**Repair Period in Calendar Days**
Gas Leaks	
Minor Gas Leak	14
Major Gas Leak less than or equal to 50,000 ppmv	5
Gas Leak greater than 50,000 ppmv	1
Liquid Leaks	
Minor Liquid Leak	3
Major Liquid Leak	1

- 5.5.6 Update to this section to reference new repair periods in Table 6. The update of this section is as follows:

  The time of the initial leak detection shall be the start of the repair period specified in Table 5 or Table 6.

- 5.5.8 New Section 5.5.8 allows up to 30 days for repair if a rig-up operation is required. The provision adds steps an operator must take to comply with the extended repair period requirement for rig-up operations. The reason

for the additional time for repair is due to the need for specialized equipment, which takes time to arrive, assemble, and install at the well site. This is prominent for well casing leaks that may require a third-party rig-up operation for repair; this is similar to the requirements in COGR. In order to be granted an extension, an operator must provide supporting information for the District to evaluate before an extension is ultimately approved. Detailed requirements are listed in Section 5.5.8 of proposed Rule 4401 and become effective after June 30, 2024.

Section 6.0 – Administrative and Recordkeeping Requirements

- 6.1.2 Update to identify California Geologic Energy Management Division (CalGEM) as the leading agency requiring facilities to maintain records of crude oil production.

- 6.2.1 Update to this section replaces the word “annually” with “each calendar year” to provide clarity on source testing frequency.

- 6.3.3.1 New Section 6.3.3.1 provides instruction on leaks identified while using OGI. The new section reads as follows:

  After June 30, 2024, all leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 6.

- 6.6 Deleted previous dates in the Operator Management Plan section as they are no longer relevant.

- 6.7 Added new language to instruct an operator to submit Operator Management Plans annually indicating any or no changes to their existing plans. Updated section reads as follows:

  By January 30 of each year, an operator shall submit to the APCO for approval, in writing, an annual report indicating any <u>or no</u> changes to an existing Operator Management Plan.

Section 7.0 – Compliance Schedule

- 7.2 Removed reference of Section 4.7, which has been deleted.

Proposed Amendments to Rule 4409

In determining potential amendments to Rule 4409, the District considered the following rules and regulations:

- Santa Barbara County Air Pollution Control District (SBCAPCD) Rule 331
- South Coast Air Quality Management District Rule (SCAQMD) 1148.1
- South Coast Air Quality Management District Rule (SCAQMD) 1173
- Ventura County Air Pollution Control District (VCAPCD) Rule 74.7
- California Oil and Gas Regulation (COGR)
- EPA 2016 Control Technology Guideline for the Oil and Gas Industry (EPA-453/B-16-001)
- EPA NSPS Subpart OOOO
- EPA NSPS Subpart OOOOa

Table 2 provides a comparison of other local, State, and Federal regulations to Rule 4409 including the District's proposed leak standards.

Table 2 – Comparison of District Rule 4409 to Similar Rules and Regulations

Rule 4409 – Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities							
Current Leak Standard	**VCAPCD Rule 74.10**	**SBCAPCD Rule 331**	**SCAQMD Rule 1173**	**SCAQMD Rule 1148.1**	**CARB COGR**	**EPA NSPS Subpart OOOO and OOOOa**	**EPA 2016 CTG for the Oil and Gas Industry (EPA-453/B-16-001)**
Gas • Minor: 200 ppmv (PRDs) • Minor: 1,000 ppmv (liquid service) • Minor: 2,000 ppmv (gas service) • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • 100 ppmv (pump in heavy liquid service) • 200 ppmv (PRDs) • 500 ppmv in light crude service • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min.	**Gas** • 100 ppmv (any component in heavy liquid service) • 500 ppmv (any component in light liquid service)	• Limit: 1,000 ppmv	• Leak Limit: 500 ppmv • Leak Limit: 2,000 ppmv for pumps in light crude service • Leak Limit: 10,000 ppmv for pumps in heavy crude service	• Leak Limit: 500 ppmv (valves, compressors, PRDs) • Leak Limit 2,000 ppmv (pumps)

Based on the above comparison, the District evaluated lowering the LDAR threshold to three specific thresholds including 1,000 ppmv, 500 ppmv, and 100 ppmv. Based on the District's analyses and cost-effectiveness analysis shown in Appendix C, the District is proposing a 500 ppmv LDAR threshold, which meets or exceeds BARCT requirements.

Reducing the leak threshold to 500 ppmv also meets RACT recommendations established in the 2016 CTG. For equipment leaks, the 2016 CTG requires monthly inspections of valves and pumps using EPA Reference Method 21 at a 500 ppmv leak threshold. The 2016 CTG also recommends annual inspections of connectors using EPA Reference Method 21 at a 500 ppmv leak threshold. As discussed earlier, quarterly inspections of all components at 500 ppmv achieve more emissions reductions than the recommended 2016 CTG requirements.

Section 1.0 – Purpose

Language updated for clarity.

Section 2.0 – Applicability

No changes proposed at this time.

Section 3.0 – Definitions

The District is proposing amendments to definitions to meet BARCT requirements, provide clarity throughout other LDAR rules, and meet RACT recommendations found in the 2016 CTG. The District is proposing a revised minor leak definition. The leak threshold is defined in Table 1 of the current rule as 2,000 ppmv for minor gas leaks. The District is establishing a lower LDAR threshold of 500 ppmv for minor gas leaks.

- 3.6 *Component*: The District removed Section 3.6.2 defining minor component from the component definition to have consistency across other District LDAR rules. A minor component is not used throughout the entire rule.

- 3.20 *Leak*: Updates to Table 1 contain new language to indicate that Table 1 is effective until June 30, 2024. The requirements of Table 2 go into effect after June 30, 2024. Table 2 contains a new minor leak definition for components other than Pressure Relief Devices (PRD). The minor leak definition in the rule is updated to reflect the lower proposed LDAR threshold. The leak threshold is defined in Table 1 of the current rule as 2,000 ppmv for minor gas leaks, and 1,000 ppmv for liquid leaks. The District is establishing a lower minor leak threshold of 500 ppmv for gas leaks, and liquid leaks.

Table 1 – Gas Leak Standards in ppmv as Methane until June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
2. Threaded Connections	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
3. Flanges	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
4. Pipes	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
5. Pumps	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
6. Compressors	Greater than 10,000	1,000 to 10,000	2,000 to 10,000
7. PRDs	Greater than 10,000	200 to 10,000	400 to 10,000
8. Polished Rod Stuffing Boxes	Greater than 10,000	1,000 to 10,000	1,000 to 10,000
9. Components not listed in 1 through 8 above	Greater than 10,000	1,000 to 10,000	2,000 to 10,000

Table 2 – Gas Leak Standards in ppmv as Methane after June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Components other than PRDs	Greater than 10,000	500 to 10,000	500 to 10,000
2. PRDs	Greater than 10,000	200 to 10,000	400 to 10,000

- 3.27 *Open-ended Line or Valve*: The District updated the definition of Open-ended Line for consistency across all the applicable rules as follows:

  Open-ended Line or Valve: *a line or valve, <u>except for pressure relief valves and process drains</u>, having one side of the line or valve seat in contact with the process fluid and one side open to the atmosphere, either directly or through an open piping*.

- 3.28 *Optical Gas Imaging (OGI)*: The District added a definition to include OGI in Rule 4409. The new definition reads as follows:

  Optical Gas Imaging (OGI): *an instrument that makes emissions visible that may otherwise be invisible to the naked eye.*

- 3.30 *Pressure Relief Device (PRD)*: The District updated the definition of a Pressure Relief Device to encompass the definition of a Pressure Relief

Valve. This provides consistency across other District LDAR rules. The new definition reads as follows:

Pressure Relief Device (PRD): a pressure relief valve, or a rupture disc, or an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere.

- 3.36 *Rig-up Operation*: The District added a new definition for "Rig-up Operation". Rig-up operations require special equipment that some facilities must contract from third parties. The circumstances and provisions are now included in Section 5.2.15 of Rule 4409 to account for Rig-up operations.

- 3.37 *Rupture Disk*: The District updated the definition to replace pressure relief valve with pressure relief device. The updated definition reads as follows:

  Rupture Disk: *a rigid diaphragm held between flanges for the purpose of isolating organic compounds from the atmosphere or from a downstream pressure relief ~~valve~~ device. Most rupture disks are designed to fail at a certain pressure point.*

Section 4.0 – Exemptions

The District is proposing to remove Section 4.2.10 from Rule 4409. Rule 4409 Section 4.2.10 exempts half inch or less stainless steel tube fittings from LDAR inspections after their initial inspection. The removal of this exemption meets RACT recommendation as the exemption of these components are not found in the 2016 CTG. These components will now be subject to the leak standard, and inspection frequency of proposed Rule 4409.

Section 5.0 – Requirements

The District is proposing to increase the frequency of LDAR inspections from annual to quarterly. The District evaluated requirements in analogous rules, including VCAPCD Rule 74.10, SBCAPCD Rule 331, and COGR, which contain quarterly inspection requirements. As such, the District is proposing to increase the frequency of LDAR inspections from annual to quarterly. Increasing the frequency of inspections will make Rule 4409 as stringent as other comparable rules and regulations in California.

- 5.1.4 *Leak Standard*: The District is replacing the word "leaking" with "in violation" for clarity in subsection 5.1.4 to describe a violation under Rule 4409.

- 5.1.4.4 *Allowable Leaks*: The District is replacing Table 3 with Table 4 after June 30, 2024. The addition of the new table will provide consistency with other District LDAR rules. The addition of Table 4 will provide consistency with the requirements under COGR and includes more stringent requirements by eliminating the distinction of component type. Previously, operators could have up to 14 leaks with fewer than 200 components inspected. The proposed amendments to Rule 4409 would allow only five (5) total components to leak regardless of component type. Additional language was added to highlight that all leaks are still subject to the leak repair timeframes. The tables read as follows:

Table 3 – Maximum Allowable Number or Percent of Leaking Components Per Inspection Period until June 30, 2024

Component	Maximum Number of Leaks for 200 or fewer Components Inspected*	Maximum Percent or Number of Leaks for more than 200 Components Inspected*
1. Valves	1	0.5% of number inspected
2. Threaded Connections	1	0.5% of number inspected
3. Flanges	1	0.5% of number inspected
4. Pumps	2	1.0% of number inspected
5. Compressors	1	1 leak
6. PRDs	1	1 leak
7. Polished Rod Stuffing Boxes	4	2.0% of number inspected
8. Other Components not listed in items 1, 2, 3, 4, 5, 6, 7, 9, and 10	1	1 leak
9. Pipes at Light Crude Oil Production Facilities or Gas Production Facilities	Maximum Number of Leaks for 200 or fewer production wells inspected	Maximum Number of Leaks for more than 200 production wells inspected
	2	1% of number inspected
10. Pipes at Natural Gas Processing Facilities	Maximum Number of Leaks	
	2	

*The maximum number of leaks in Table 3 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components of a given type inspected during the specified inspection period. Leaks counted toward the allowable leaks in Table 3 are still subject to maintenance requirements of section 5.3.

Table 4 – Maximum Allowable Number or Percent of Leaking Components Per Inspection Period after June 30, 2024

	Leak Threshold 200 or Less Components Inspected	More than 200 Components Inspected
500-9,999 ppmv	5	2% of total inspected
10,000-49,999 ppmv	2	1% of total inspected

* The maximum number of leaks in Table 4 shall be rounded upwards to the nearest integer, where required. The maximum allowable percent of leaks is calculated from the total number of components of a given type inspected during the specified inspection period. Leaks counted toward the allowable leaks in Table 4 are still subject to maintenance requirements of section 5.3.

- 5.2.2 The District updated language in this section to provide clarity. The updated section reads as follows:

  For unmanned light crude oil production facilities, natural gas production facilities, or gas processing facilities, the operator shall audio-visually inspect for leaks of all accessible operating pumps, compressors, PRDs in service at least once per calendar week.

- 5.2.8.2 Update to identify California Geologic Energy Management Division (CalGEM) as the leading agency requiring facilities to maintain records of annual pipe inspections.

- 5.2.9 *Annual Inspection*: The District will phase out Section 5.2.9. This will eliminate the possibility to revert to an annual leak inspection for components subject to Rule 4409. The District is requiring only quarterly inspection for all components subject to Rule 4409.

- 5.2.10 *Annual Inspection Violation*: The District will phase out Section 5.2.10. Section 5.2.10 is no longer relevant under proposed Rule 4409 with the phase out of Section 5.2.9. Proposed Rule 4409 will no longer allow annual inspection, and operators must inspect components subject to Rule 4409 quarterly at 500 ppmv.

- 5.2.11 *Notification to APCO of Annual Inspection*: The District will sunset Section 5.2.11, Notification to APCO of Annual Inspection, since this language is no longer relevant under proposed Rule 4409 with the phase out of section 5.2.9. Proposed Rule 4409 will no longer allow annual inspection, and operators must inspect components subject to Rule 4409 quarterly.

- 5.2.15 New Section 5.2.15 added to allow up to 30 days for repair if a rig-up operation is required. The provision adds steps an operator must take to comply with the extended repair period requirement for rig-up operations. The reason for the additional time for repair is due to the need for

specialized equipment, which takes time to arrive, assemble, and install at the well site. This is prominent for well casing leaks that may require a third-party rig-up operation for repair; this is similar to the requirements in COGR. In order to be granted an extension, an operator must provide supporting information for the District to evaluate before an extension is ultimately approved. Detailed requirements are listed in section 5.2.15 of proposed Rule 4409 and become effective after June 30, 2024.

- 5.3.5 Update to reference new repair period Table 6 in Rule 4409 after June 30, 2024. The BARCT analysis concluded more stringent repair periods for major gas leaks, and liquid leaks. New Table 6 is as follows:

Table 5 – Repair Period until June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 1)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	2	0
Liquid Leaks		
Minor Liquid Leak (See Section 3.22.2)	3	0
Major Liquid Leak (See Section 3.22.1)	2	0

Table 6 – Repair Period after June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 2)	7	0
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than or equal to 50,000 ppmv	1	0
Liquid Leaks		
Minor Liquid Leak	1	0
Major Liquid Leak	1	0

Section 6.0 – Administrative and Recordkeeping Requirements

- 6.1.4 Added new language to instruct an operator to submit Operator Management Plans annually indicating any or no changes to their existing plans. Updated section reads as follows:

  By January 30 of each year, an operator shall submit to the APCO for approval, in writing, an annual report indicating any or no changes to an existing Operator Management Plan.

- 6.3.2 New Section 6.3.2 provides instruction on leaks identified while using OGI. The new section reads as follows:

  After June 30, 2024, All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 6.

Section 7.0 Compliance Schedule

- 7.1 Section deleted to remove outdated language.

- 7.2 Section deleted to remove outdated language.

Proposed Amendments to Rule 4455

The District is proposing to lower the LDAR threshold for this Rule. In determining the LDAR thresholds evaluated, the District considered LDAR thresholds from the following agencies and associated rules, and regulations:

- Bay Area Air Quality Management District (BAAQMD) Regulation 8 Rule 18
- Santa Barbara County Air Pollution Control District (SBCAPCD) Rule 331
- South Coast Air Quality Management District (SCAQMD) Rule 1173
- Ventura County Air Pollution Control District (VCAPCD) Rule 74.7
- EPA NSPS Subpart OOOO
- EPA NSPS Subpart OOOOa

Table 3 provides a comparison of the District's proposed requirements under Rule 4455 to other local, State, and Federal regulations.

Table 3 – Comparison of District Rule 4455 to Similar Rules and Regulations

Rule 4455 – Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants					
Current Leak Standard	**VCAPCD Rule 74.7**	**SBCAPCD Rule 331**	**BAAQMD Regulation 8 Rule 18**	**SCAQMD Rule 1173**	**EPA NSPS Subpart OOOO and OOOOa**
Gas • Minor: 100 ppmv (PRDs in liquid service) • Minor: 200 ppmv (PRDs in gas service) • Minor: 200 ppmv (valves, threaded connections, and flanges in liquid service) • Minor: 400 ppmv (valves, threaded connections, and flanges in gas service) • Minor: 500 ppmv (pumps, compressors and other component types in liquid service) • Minor: 1,000 ppmv (pumps, compressors and other component types in gas service) • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • 100 ppmv (all other components except the ones with 500 ppmv) • 500 ppmv (pumps, compressors, PRDs)	**Gas** • 100 ppmv (pump in heavy liquid service) • 200 ppmv (PRDs) • 500 ppmv in light crude service • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min.	• Leak Limit: 500 ppmv • Leak Limit: 2,000 ppmv for pumps in light crude service • Leak Limit: 10,000 ppmv for pumps in heavy crude service

Based on the above comparison, the District already includes stringent levels for most of the categories. However, the District evaluated lowering the LDAR threshold for "*Minor leak for pumps, compressors and other component types in gas service*" category from 1,000 ppmv to 500 ppmv and 100 ppmv. Based on the District's analyses and cost-effectiveness analysis shown in Appendix C, the District is proposing a 500 ppmv LDAR threshold, which meets or exceeds BARCT requirements.

Section 1.0 – Purpose

Update to language for consistency and clarity. Update reads as follows:

The purpose of this rule is to limit Volatile Organic Compound (VOC) emissions from leaking components at petroleum refineries, gas liquids processing facilities, and chemical plants.

Section 2.0 – Applicability

No changes proposed at this time.

Section 3.0 – Definitions

The District is proposing amendments to definitions to meet BARCT requirements. The District is proposing a revised minor leak definition to reflect the proposed LDAR threshold. The leak threshold is defined in Table 1 of the current rule as 1,000 ppmv for select components. The District is establishing a lower LDAR threshold of 500 ppmv for minor gas leaks on components that are not already lower.

- 3.7.1 *Major Component*: Update to definition for consistency and clarity. The change to the definition is as follows:

  Major Component: *a pump five (5) brake horsepower or larger, any compressor, or any pressure relief ~~valve~~ device four (4) inches in diameter or larger.*

- 3.7.2 The District removed Section 3.7.2 defining minor component from the component definition to have consistency across other District LDAR rules. A minor component is not used throughout the entire rule.

- 3.22 *Leak*: Updates to Table 1 contain new language to indicate that Table 1 is effective until June 30, 2024. The requirements of Table 2 go into effect after June 30, 2024. Table 2 contains a new minor leak definition only for compressors, pumps, and other component types not listed in 1 through 5 as listed in Table 2. The minor leak definition in the Rule is updated to reflect the lower proposed LDAR thresholds.

Table 1 – Gas Leak Standard in ppmv as Methane until June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	200 to 10,000	400 to 10,000
2. Threaded connections	Greater than 10,000	200 to 10,000	400 to 10,000
3. Flanges	Greater than 10,000	200 to 10,000	400 to 10,000
3. Pumps	Greater than 10,000	500 to 10,000	1,000 to 10,000
4. Compressors	Greater than 10,000	500 to 10,000	1,000 to 10,000
5. PRD	Greater than 10,000	100 to 10,000	200 to 10,000
6. Other component types not listed in 1 through 5 above	Greater than 10,000	500 to 10,000	1,000 to 10,000

Table 2 – Gas Leak Standard in ppmv as Methane after June 30, 2024

Type of Component	Major Gas Leak	Minor Gas Leak	
		Components in Liquid Service	Components in Gas/Vapor Service
1. Valves	Greater than 10,000	200 to 10,000	400 to 10,000
2. Threaded connections	Greater than 10,000	200 to 10,000	400 to 10,000
3. Flanges	Greater than 10,000	200 to 10,000	400 to 10,000
3. Pumps	Greater than 10,000	500 to 10,000	500 to 10,000
4. Compressors	Greater than 10,000	500 to 10,000	500 to 10,000
5. PRD	Greater than 10,000	100 to 10,000	200 to 10,000
6. Other component types not listed in 1 through 5 above	Greater than 10,000	500 to 10,000	500 to 10,000

- 3.25 *Open-ended Line or Valve*: The District updated the definition of Open-ended Line for consistency across all the applicable rules as follows:

  Open-ended Line or Valve: *a line or valve, <u>except for pressure relief valves and process drains</u>, having one side of the line or valve seat in contact with the process fluid and one side open to the atmosphere, either directly or through an open piping*.

- 3.26 *Optical Gas Imaging (OGI)*: The District added a definition to include OGI. The new definition reads as follows:

  Optical Gas Imaging (OGI): *an instrument that makes emissions visible that may otherwise be invisible to the naked eye.*

- *3.28* *Pressure Relief Device (PRD)*: The District updated the definition of Pressure Relief Devices (PRD) to encompass the definition of a Pressure Relief Valve. This provides consistency across other District LDAR rules. The new language prompts the removal of existing definition 3.28, Pressure Relief Valve (PRV).

- 3.31 *Process Pressure Relief Device*: Update to the definition to provide clarity. Updated section reads as follows:

  Process Pressure Relief Device: *a <u>Pressure Relief Device</u> (PRD) that is vented to the atmosphere and is located on a process equipment other than storage tanks, liquefied petroleum gas storage vessels, or pipelines used to transport materials.*

- 3.37 *Rupture Disk*: The District updated the definition to replace pressure relief valve with pressure relief device. The updated definition reads as follows:

  Rupture Disk: *a rigid diaphragm held between flanges for the purpose of isolating organic compounds from the atmosphere or from a downstream pressure relief ~~valve~~ <u>device</u>. Most rupture disks are designed to fail at a certain pressure point.*

Section 4.0 – Exemptions

The District is proposing to remove exemption 4.2.8 from Rule 4455. Rule 4455 Section 4.2.8 exempts half inch or less stainless steel tube fittings from LDAR inspections after their initial inspection. The removal of this exemption will provide consistency across other District LDAR rules and provide stringency to Rule 4455.

Section 5.0 – Requirements

Proposed amendments would phase out the ability for operators to apply for approval to change their inspection frequency from quarterly to annually for specific component types. Quarterly inspections ensure the implementation of required reductions for the District's various attainment plans.

- 5.1.4 *Leak Standard*: The District is replacing the word "leaking" with "in violation" for clarity in subsection 5.1.4 to describe a violation under Rule 4455.

- 5.1.4.4 *Allowable Leaks*: Additional language was added to highlight that all leaks are still subject to the leak repair timeframes as follows:

  Leaks counted toward the allowable leaks in Table 3 are still subject to maintenance and repair requirements of Section 5.3.

- 5.2.8 *Annual Inspection*: The District will phase out Section 5.2.8. This will eliminate the possibility to revert to an annual leak inspection for components subject to Rule 4455. The District is requiring only quarterly inspection for all components subject to Rule 4455.

- 5.2.9 Added language to phase out the ability for an operator to request a change in their inspection frequency from quarterly to annually for specific component types.

- 5.2.10 Added language to phase out Section 5.2.10. Section is no longer needed since operators will not revert to annual inspections.

- 5.3.5 Update to reference new repair period Table 5 in Rule 4455 after June 30, 2024. The BARCT analysis concluded more stringent repair periods are required. Updates are referenced in new Table 5 is as follows:

Table 4 – Repair Period until June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 1)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	2	0
Liquid Leaks		
Minor Liquid Leak (See Section 3.22.2)	3	0
Major Liquid Leak (See Section 3.22.1)	2	0

Table 5 – Repair Period After June 30, 2024

Type of Leak	Repair Period in Calendar Days	Extended Repair Period in Calendar Days
Gas Leaks		
Minor Gas Leak (See Table 2)	7	7
Major Gas Leak greater than 10,000 ppmv but equal to or less than 50,000 ppmv	3	2
Major Gas Leak greater than 50,000 ppmv	1	0
Liquid Leaks		
Minor Liquid Leak (See Section 3.22.2)	1	0
Major Liquid Leak (See Section 3.22.1)	1	0

Section 6.0 – Administrative and Recordkeeping Requirements

- 6.1.4 Added new language to instruct an operator to submit Operator Management Plans annually indicating any or no changes to their existing plans. Updated section reads as follows:

  By January 30 of each year, an operator shall submit to the APCO for approval, in writing, an annual report indicating any or no changes to an existing Operator Management Plan.

- 6.2.2 Section will phase out and will be replaced by new Section 6.2.3

- 6.2.3 Added new language to clarify that leaks detected during quarterly operator inspection must be submitted to the APCO, CARB, or EPA upon request. New section reads as follows:

  After June 30, 2024, records of leaks detected by operator inspection, and each subsequent repair and re-inspection, shall be submitted to the APCO, ARB, and US EPA upon request.

- 6.4.1.1 New subsection in 6.4.1.1 provides instruction on leaks identified while using OGI. The new section reads as follows:

  After June 30, 2024, All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 4.

Section 7.0 – Compliance Schedule

- 7.1 Section deleted to remove outdated language.

- 7.2 Language added to phase out compliance schedule from previous amendment.

Proposed Amendments to Rule 4623

In determining potential amendments to Rule 4623, the District considered the following rules and regulations:

- Bay Area Air Quality Management District (BAAQMD) Regulation 8 Rule 5
- Santa Barbara County Air Pollution Control District (SBCAPCD) Rule 331
- South Coast Air Quality Management District Rule (SCAQMD) 463
- Ventura County Air Pollution Control District (VCAPCD) Rule 74.10
- California Oil and Gas Regulation (COGR)
- EPA 2016 Control Technology Guideline for the Oil and Gas Industry (EPA-453/B-16-001)
- EPA NSPS Subpart OOOO
- EPA NSPS Subpart OOOOa

Table 4 provides a comparison of the District's proposed requirements under Rule 4623 to other local, State, and Federal regulations.

Table 4 – Comparison of District Rule 4623 to Similar Rules and Regulations

Rule 4623 – Storage of Organic Liquids							
Current Leak Standard	**VCAPCD Rule 74.10**	**SBCAPCD Rule 331**	**BAAQMD Regulation 8 Rule 5**	**SCAQMD Rule 463**	**CARB COGR**	**EPA NSPS Subpart OOOO and OOOOa**	**EPA 2016 CTG for the Oil and Gas Industry (EPA-453/B-16-001)**
Gas • Minor: 10,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • Minor: 1,000 ppmv • Major: 10,000 ppmv **Liquid** • Minor: +3 drops min. • Major: continuous flow	**Gas** • 100 ppmv (all other components except the ones with 500 ppmv) • 500 ppmv (pumps, compressors, PRDs)	**Gas** • 500 ppmv (any tank with a capacity of 19,815 gallons or greater)	• Limit: 1,000 ppmv	• Leak Limit: 500 ppmv • Leak Limit: 2,000 ppmv for pumps in light crude service • Leak Limit: 10,000 ppmv for pumps in heavy crude service	• Leak Limit: 500 ppmv (valves, compressors, PRDs) • Leak Limit 2,000 ppmv (pumps) • Tanks with the PTE more than 6 Tons/year of VOC are recommended to be on Vapor Recovery or keep emissions under 4 tons/year

Based on the above comparison, the District evaluated lowering the LDAR threshold to 1,000 ppmv, 500 ppmv, and 100 ppmv. Based on the District's analyses and cost-effectiveness analysis shown in Appendix C, the District is proposing a 500 ppmv LDAR threshold, which meets or exceeds BARCT requirements.

Section 1.0 – Purpose

Language updated for clarity and consistency.

Section 2.0 – Applicability

To address the comments from EPA's TSD for the 2016 CTG, the District added the following language to clarify control requirements on storage tanks:

This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held, or stored, and any tank used in crude oil or natural gas production operations with a potential to emit six (6) tons of VOC or greater per year.

Section 3.0 – Definitions

The District added multiple definitions for clarity and consistency between the District LDAR rules.

- 3.4 *Component*: New definition added for clarity, consistency across other District rules. The component definition reads as follows:

  Component: *includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure-vacuum relief valve, pressure relief device, pipe, flange, process drain, sealing mechanism, hatch, sight-glass, meter, or seal fluid system in VOC service. This definition includes tanks and separators.*

- 3.5 *Compressor*: New definition added for clarity, consistency across other District rules. The new compressor definition reads as follows:

  Compressor: *a device used to compress gases or vapors or a combination of gases and vapors by the addition of energy, and includes all associated components used for connecting and sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) connected on the body of the compressor. For example, a valve that is connected to a threaded hole on body of the compressor, the first VOC leak point is the threaded connection on the body side of the compressor, but the valve itself is not a "first VOC leak point". Similarly, a compressor shaft seal is considered as a first "VOC leak point".*

- 3.6 *Compressor Part*: New definition added for clarity, consistency across other District rules, and to assist in Section 5.9.4.9 and Section 3.5. The new definition reads as follows:

  Compressor Part: *for the purpose of Section 5.9.4.9, a compressor part refers to the "first VOC leak point" as explained in Section 3.5.*

- 3.14 *Gas Leak*: Updates to Table 1 contain new language to indicate that Table 1 is effective until June 30, 2024. The requirements of new Table 2 go into effect after June 30, 2024. Table 2 contains a new minor leak definition for components subject to Rule 4623. Components will have a minor gas leak threshold of 500 ppmv, and a major gas leak threshold of 10,000 ppmv or greater.

Table 1 – Gas Leak (Until June 30, 2024)	
	Gas Leak
Components	Greater than 10,000

Table 2 – Gas Leak (After June 30, 2024)		
	Minor Gas Leak	Major Gas Leak
Components	500 to 10,000	Greater than 10,000

- 3.19 *Inaccessible Component*: New definition added for clarity, consistency across other District rules as follows:

  Inaccessible Component: *a component that is located over 15 feet above ground when access is required from the ground; or a component that is located over six (6) feet away from a platform when access is required from the platform, or a component in a location that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.*

- 3.22 *Leak Minimization*: New definition added for clarity, consistency across other District rules on the practice for safely minimizing a leak on component without stopping or slowing down production. The new definition reads as follows:

  Leak Minimization: *reducing a leak to the lowest achievable level without damaging the component using best modern practices which include, but are not limited to, adding sealing material to the component, tightening the component, or adjusting the component without shutdown of the process that the component serves and that can be safely accommodated.*

- 3.28 *Optical Gas Imaging (OGI)*: The District added a definition to include OGI. The new definition reads as follows:

  Optical Gas Imaging (OGI): *an instrument that makes emissions visible that may otherwise be invisible to the naked eye.*

- 3.30 *Process Drain*: New definition added for clarity, consistency across other District rules as follows:

  Process Drain: *any open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources.*

- 3.32 *Pressure Relief Device (PRD)*: New definition added for clarity, consistency across other District rules. The new definition reads as follows:

  Pressure Relief Device (PRD): *a pressure relief valve, a rupture disk, or an automatic pressure-relieving device associated with a process vessel or piping system that is activated by pressure upstream of the device and relieves to the atmosphere.*

- 3.33 *Pump*: New definition added for clarity, consistency across other District rules. The new definition reads as follows:

  Pump: *a device used to transport fluids by the addition of energy, and includes all associated components used for connecting or sealing purposes. The phrase "all associated components used for connecting and sealing purposes" means the first VOC leak points (first components) on the body of the pump. For example, a valve that is connected to a threaded hole on body of the pump, the first VOC leak point is the threaded connection on the body side of the pump, but the valve itself is not a "first VOC leak point." Similarly, a pump shaft seal is considered as a first "VOC leak point".*

- 3.34 *Pump Part*: New definition added for clarity, consistency across other District rules. The purpose of this definition is to further clarification of a pump in Section 3.33.

- 3.40 *Tank*: Updated the definition of a tank under Rule 4623. The definition update is necessary to further define which components are considered part of the tank or separate components. This definition provides clarity to the existing rule. The update reads as follows:

  Tank: *any stationary container, reservoir, or vessel, in which an organic liquid is placed, held, or stored. <u>This definition includes components connected to the body of the tank. For example, a valve that is connected to a threaded hole on the body of the tank, the first VOC leak point is the threaded connection on the body side of the tank, but the valve itself is a separate component from the tank.</u>*

- 3.44 *Unsafe-to-Monitor Component*: New definition added for clarity, consistency across other District rules. The new definition reads as follows:

  Unsafe-to-Monitor Component: *a component installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.*

Section 4.0 – Exemptions

To address the comments from EPA's TSD for the 2016 CTG, the District added language to clarify control requirements on storage tanks and is proposing to remove, or modify the following exemptions in Section 4.0:

- 4.1.3 The following language is being added to the *Storage Tanks Used for Clean Produced Water* section:

  Tanks that are used for storage/processing of clean produced water, or other water that meets the VOC standard specified in the definition of "clean produced water" in Rule 1020 (Definitions) unless the tank has a potential to emit six (6) tons of VOC emissions or greater per year and is used in crude oil and natural gas production operations.

- 4.4 *Storage Tanks Handling Organic Liquid with TVP Less Than 0.5*: The District is modifying Section 4.4 from Rule 4623. The District is proposing to modify this section to include tanks with liquid TVP 0.1 psia or greater.

- 4.4.5 New section added for storage tanks degassing and interior cleaning requirements. This new section will still require exempt tanks to follow the cleaning provisions of Section 5.7.5 of Rule 4623. The new section reads as follows:

  After June 30, 2024, operators shall follow the storage tank degassing and interior cleaning requirements pursuant to Section 5.7.5 for notification, recordkeeping, tank degassing, tank cleaning, and sludge removal.

Section 5.0 – Requirements

- 5.1 New tables created to establish new control system requirement for tanks that are less than 0.5 TVP to provide consistency between other District rules and to ensure that the District is meeting BARCT.

Table 4 – General VOC Control System Requirements after June 30, 2024

Tank Capacity (Gallons)	True Vapor Pressure (TVP) of Organic Liquid			
	0.1 psia to <0.5 psia	0.5 psia to <1.5 psia	1.5 psia to <11 psia	≥11.0 psia
(Group A) 1,100 to 19,800	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group B) >19,800 to 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group C) >39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system

Table 6 – Small Producer VOC Control System Requirements for Crude Oil Storage Tanks after June 30, 2024

Tank Capacity (gallons)	TVP and Crude Oil Throughput			
	0.1 psia to <11 psia and a tank throughput of >50 to <150 barrels of crude oil per day	0.1 psia to <0.5psia and a tank throughput ≥150 barrels of crude oil per day	0.5 psia to <11 psia and a tank throughput ≥150 barrels of crude oil per day	≥11 psia and regardless of crude oil tank throughput
(Group A) 1,100 to 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group B) >39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system

5.1.1.1 Current District Rule 4623 requires vapor control systems based on size of tank and TVP of the stored liquid. EPA's CTG requires a vapor control system based on if the PTE of storage tank equals or exceeds six (6) tons per year and if the actual VOC emissions exceed four (4) tons per year. However, to ensure that there is no deficiency in meeting the CTG requirements, the District is proposing to add the following language:

If a tank has the Potential to Emit greater than or equal to six (6) tons per year of VOC and actual emissions are greater than or equal to four (4) tons per year using a generally accepted model or calculation methodology, operator must install a vapor control system meeting the specifications described in Sections 5.3, 5.4, 5.5 or 5.6.

5.1.2.1 Current District Rule 4623 requires vapor control systems based on size of tank and TVP of the stored liquid. EPA's CTG requires a vapor control system based on if the PTE of storage tank equals or exceeds six (6) tons per year and if the actual VOC emissions exceed four (4) tons per year. However, to ensure there is no deficiency in meeting the CTG requirements, the District is proposing to add the following language:

If a tank has the Potential to Emit greater than or equal to six (6) tons per year of VOC and actual emissions are greater than or equal to four (4) tons per year using a generally accepted model or calculation methodology, operator must install a vapor control system meeting the specifications described in Sections 5.3, 5.4, 5.5 or 5.6.

- 5.3.1.3 *Specifications for External Floating Roof Tanks:* Update to Section 5.3.1.3 now reduces the time an operator must notify the District of a roof landing from five (5) days to three (3) days allowing operators faster response time to ensure proper maintenance of their tanks.

- 5.4.1 *Specifications for Internal Floating Roof Tanks*: Updated section to reduce the minimum vertical distance an internal floating roof tank seal can extend above the stored liquid surface from 18 inches to 6 inches, which is consistent with requirements found in other districts and would allow for newer seal technologies to operate within these parameters without any impact in emissions.

- 5.5.1 Update to Section 5.5.1 provides a new reference of a pressure vacuum valve.

- 5.5.2.2.1 *Requirements for External Floating Roof Deck Fittings:* Updated language to provide consistency and clarity. Updated section reads as follows:

  Except for automatic bleeder vents and rim vents and pressure-vacuum relief ~~vents~~ valves, each opening in a non-contact external floating roof shall provide a projection below the liquid surface.

- 5.6.1.1 *Specifications for Vapor Recovery Systems*: Update to identify California Geologic Energy Management Division (CalGEM) as follows:

  A condensation or vapor return system that connects to one of the following: a gas processing plant, a field gas pipeline, a pipeline distributing Public Utility Commission quality gas for sale, an injection well for disposal of vapors as approved by the ~~Department of Oil, Gas, and Geothermal Resources (DOGGR)~~ California Geologic Energy Management Division (CalGEM).

- 5.7 New language added to phase out the Voluntary Tank Preventive Inspection and Maintenance, and Tank Cleaning Program. Tanks will now be required to comply with Rule 4623 new LDAR provisions after June 30, 2024. Edits to the tables found in this section reflect the phase out date of June 30, 2024 of all three tables in the voluntary tank inspection and maintenance program.

- 5.7.5 New section added to specify tank maintenance activities after June 30, 2024. New section reads as follows:

  After June 30, 2024, operators of Fixed and Floating Roof Tanks shall comply with the provisions of Section 5.7.5. Operators may disconnect from vapor recovery provided that the procedures are performed as expeditiously as practicable and emissions are minimized to the maximum extent practicable.

- 5.7.5.3 *Fixed-Roof Tank Operating Only a Pressure-Vacuum Relief Valve*: section updated to provide consistency with other requirements in Rule 4623. The update reads as follows:

  Except for complying with Section 5.7.5.3.2 requirements, fixed-roof tanks allowed, pursuant to Tables 3, Table 4, Table 5 and Table 6 of this rule, to operate with a pressure-vacuum relief valve ~~as the primary VOC control system~~ are not subject to the degassing requirements specified in Section 5.7.5.4.

- 5.7.5.4 *Tank Degassing Requirements*: Updated to account for the TVP exemption change in Section 4.4. The changes phase out the section

where the rule references TVP 0.5 psia and introduces TVP 0.1 psia after June 30, 2024.

- 5.7.5.6 Updated to phase out all three of the Voluntary Tank Preventive Inspection and Maintenance, and Tank Cleaning Program tables.

- 5.8 *Preventive Maintenance and Interior Cleaning Requirements for Fixed Roof Tanks*: New section added to require operators of fixed roof tanks to adhere to the maintenance and cleaning activities pursuant to Section 5.7.5 of Rule 4623.

- 5.9.1 *Inspection and Re-Inspection Requirements*: New section and subsections added to establish an LDAR program for all components subject to Rule 4623. Section 5.9.1 defines a violation as the following:

    - 5.9.1.1 The discovery of a major gas leak greater than 10,000 ppmv.

    - 5.9.1.2 The discovery of a liquid leak as defined in Section 3.23.

    - 5.9.1.3 Exceeding the allowable number of minor leaks defined in Table 8.

    - 5.9.1.4 Failure to repair leaks within the timeframes specified in Table 9.

Table 8 – Allowable Leaks		
Leak Threshold	200 or Less Components Inspected*	More than 200 Components Inspected*
500-9,999 ppmv	5	2% of total inspected

**Effective after June 30, 2024*

- 5.9.2 *Determination of Compliance with the Leak Standards during Operator Inspection*: New section added to establish a violation if a facility does not repair a leak within the timeframes of new Table 9.

- 5.9.3 New section added for leaks discovered during operator and District inspections above the leak thresholds defined in Section 3.14 and in Table 2 under the time frames of the following Table 9, that take effect after June 30, 2024:

Table 9 – Repair Time Periods	
Leak Threshold	Repair Time Period
Minor Leak	14 Calendar Days
Major Leak	2 Calendar Days
Liquid Leak	2 Calendar Days

- 5.9.4 New Section 5.9.4 added that establishes quarterly LDAR for components subject to Rule 4623. This section also highlights that current requirements to inspect external floating roof tanks and internal floating roof tanks remain the same, as per Section 6.1.3 and Section 6.1.4.

- 5.9.4.1 New Section 5.9.4.1 establishes the requirement to test for leaks of total hydrocarbons in units of ppmv in accordance with U.S. EPA Reference Method 21.

- 5.9.4.2 New Section 5.9.4.2 establishes a 12-month timeframe to inspect inaccessible and unsafe-to-monitor components using U.S. EPA Reference Method 21.

- 5.9.4.3 New Section 5.9.4.3 establishes a 24-hour requirement for audio-visual inspections for components not considered inaccessible, unsafe-to-monitor, floating roof tanks, deck fittings. Audio-visual inspections are allowed once a week for facilities that are not visited at least once every 24-hours.

- 5.9.4.4 New Section 5.9.4.4 provides further guidance for operators whenever a leak is detected while conducting an audio-visual inspection. U.S. EPA Reference Method 21 must be conducted within 24-hours after a leak detected while doing an audio-visual inspection.

- 5.9.4.5 New Section 5.9.4.5 requires operators to inspect all new, replaced, or repaired fittings flanges, and threaded connections within 72 hours of placing the component in service.

- 5.9.4.6 New Section 5.9.4.6 states that a District inspection does not qualify as quarterly operator inspection. District inspections are conducted to determine compliance with District rules, and shall not replace the mandatory operator inspection for components subject to Rule 4623.

- 5.9.4.7 New Section 5.9.4.7 requires operators to tag leaking components with visible identification that includes the date and time of a leak detection and the measured leak concentration.

- 5.9.4.8 New Section 5.9.4.8 requires components, with the exclusion of tanks, to be replaced if five repair actions occur within a rolling 12-month period.

- 5.9.4.9 New Section 5.9.4.9 requires operators to attempt to minimize all component leaks immediately to the maximum extent possible, but no later than one hour after detection of the leak in order to stop or reduce leakage to the atmosphere.

- 5.9.4.10 New Section 5.9.4.10 requires an operator to comply with at least one of the requirements of the following Sections (5.9.4.10.3, 5.9.4.10.4 or 5.9.4.10.5) as soon as practicable but not later than the time period specified in Table 9 if a leak still exceeds the applicable leak standards. Determination of the leak standards is referenced in Sections 5.9.4.10.1 and 5.9.4.10.2.

    - *5.9.4.10.1 The leak rate measured, after leak minimization has been performed, shall be the leak rate used to determine the repair period specified in Table 9.*
    - *5.9.4.10.2 The start of the repair period shall be the time of the initial leak detection.*
    - *5.9.4.10.3 Repair or replace the leaking component; or*
    - *5.9.4.10.4 Vent the leaking component to a VOC control system as defined in Section 3.1; or*
    - *5.9.4.10.5 Remove the leaking component from operation.*

Section 6.0 – Administrative and Recordkeeping Requirements

- 6.1.3.1 *External Floating Roof Tank Inspection*: Added the word “roof” to provide clarity that this section is referencing floating roof tanks. New section reads as follows:

    Inspect all floating <u>roof</u> tanks at least once every 12 months to determine compliance with the requirements of this rule. The actual gap measurements of the floating roof primary and secondary seals shall be recorded. The inspection results shall be submitted to the APCO as specified in Section 6.3.5.

- 6.1.4.3 *Internal Floating Roof Tank Inspection*: New language added for Internal Floating Roof Tanks. The new language instructs operators to submit results of seal gap measurements and seals to the APCO as specified in Section 6.3.5.

- 6.2 *TVP and API Gravity Testing of Stored Organic Liquid in Uncontrolled Fixed Roof Tanks*: Modifications to the TVP and API gravity requirements to provide clarity for the sampling location and frequency of sampling.

Section 6.2.2 and 6.2.3 were removed from the rule to ensure all tanks subject to the 2016 CTG recommendations comply with the requirements of Rule 4623.

- 6.3.4 *Recordkeeping*: Updated to identify CalGEM as the leading agency requiring recordkeeping for throughput of crude oil for exempt tanks under Rule 4623.

- 6.3.8 *Recordkeeping*: New section added to provide clarity on recordkeeping for tanks operating under Sections 5.1.1.1 and 5.1.2.1. The new section reads as follows:

  An operator who is demonstrating that their tank PTE emissions are below six (6) tons of VOC per year or actual emissions are below four (4) tons of VOC per year shall keep an accurate record of each organic liquid stored in each tank, including storage temperature, TVP, and monthly throughput.

- 6.3.9 *Inspection Log*: New section added to establish an inspection log regimen for inspections, tracking of leaking components, and records of calibration of detection instruments. This new section provides consistency across other District rules with LDAR programs.

- 6.4.2 *Test and Inspection Methods*: Updated methods referenced to provide the most up-to-date methodology.

- 6.4.8.1 *Test and Inspection Methods*: New section added to establish OGI.

Section 7.0 – Compliance Schedule

- 7.1 Section deleted to remove outdated language.

- 7.2 New section added to establish a compliance deadline for LDAR requirements and other new sections of Rule 4623 as follows:

Table 10 – Compliance Schedule

	Authority to Construct	Full Compliance
Leak Standards (Table 2), Inspection and Re-Inspection Requirements in Section 5.9	N/A	July 1, 2024
Tanks required to comply with Sections 5.1.1.1, 5.1.2.1, or required to install a pressure-vacuum relief valve	March 31, 2024	12 months after issuance of ATC

Proposed Amendments to Rule 4624

In determining potential amendments to Rule 4624, the District considered the following rules and regulations:

- Bay Area Air Quality Management District (BAAQMD) Regulation 8 Rule 5
- Sacramento Metropolitan Air Quality Management District (SMAQMD) Rule 447
- Santa Barbara County Air Pollution Control District (SBCAPCD) Rule 346
- South Coast Air Quality Management District Rule (SCAQMD) 462
- Ventura County Air Pollution Control District (VCAPCD) Rule 71.3
- EPA NSPS Subpart OOOO
- EPA NSPS Subpart OOOOa

Table 5 provides a comparison of the District's proposed requirements under Rule 4624 to other local, State, and Federal regulations.

Table 5 – Comparison of District Rule 4624 to Similar Rules and Regulations

Rule 4624 – Transfer of Organic Liquid								
Current Leak Standard	**VCAPCD Rule 71.3**	**SBCAPCD Rule 346**	**BAAQMD Regulation 8 Rule 5**	**SCAQMD Rule 462**	**SMAQMD Rule 447**	**CARB COGR**	**EPA NSPS Subpart OOOO and OOOOa**	**EPA 2016 CTG for the Oil and Gas Industry (EPA-453/B-16-001)**
Gas • Leak: 1,000 ppmv **Liquid** • Leak: +3 drops min.	**Gas** • Leak: 10,000 ppmv	**Gas** • Leak: 10,000 ppmv	**Gas** • 100 ppmv (all other components except the ones with 500 ppmv) • 500 ppmv (pumps, compressors, PRDs)	**Gas** • Leak: 3,000 ppmv **Liquid** • Leak: +3 drops min.	**Gas** • Leak: 10,000 ppmv **Liquid** • Leak: +3 drops min.	• Limit: 1,000 ppmv	• Leak Limit: 500 ppmv • Leak Limit: 2,000 ppmv for pumps in light crude service • Leak Limit: 10,000 ppmv for pumps in heavy crude service	• Leak Limit: 500 ppmv (valves, compressors, PRDs) • Leak Limit 2,000 ppmv (pumps)

Based on the above comparison, the District evaluated lowering the LDAR threshold to 1,000 ppmv, 500 ppmv, and 100 ppmv. Based on the District's analyses and cost-effectiveness analysis shown in Appendix C, the District is proposing a 500 ppmv LDAR threshold, which meets BARCT requirements.

Section 1.0 – Purpose

Language updated for clarity. Updated section reads as follows:

The purpose of this rule is to limit Volatile Organic Compound (VOC) emissions from the transfer of organic liquids.

Section 2.0 – Applicability

No changes proposed at this time.

Section 3.0 – Definitions

The District added multiple definition for clarity and consistency between the District LDAR rules. The District is proposing new definitions to identify components, compressors, compressor part, leak minimization, inaccessible component, pump, pump part and unsafe-to-monitor components.

- 3.10 *Closed VOC Emission Control System:* Update to existing definition to identify California Geologic Energy Management Division (CalGEM) as the leading agency for disposal of vapors.

- 3.11 *Component*: New definition added for clarity of what a component is under Rule 4624. New definition reads as follows:

  Component: includes, but is not limited to, any valve, fitting, threaded connection, pump, compressor, pressure relief device, pipe, flange, process drain, sealing mechanism, sight-glass, meter, or seal fluid system, separators, and pressure vessels in VOC service.

- 3.18 *Inaccessible Component*: New definition added for clarity to define an inaccessible component in Rule 4624. This provides consistency to the new LDAR program introduced in Rule 4624 and reads as follows:

  Inaccessible Component: *a component that is located over 15 feet above ground when access is required from the ground; or a component that is located over six (6) feet away from a platform when access is required from the platform, or a component in a location that would require the elevation of monitoring personnel higher than six (6) feet above permanent support surfaces.*

- 3.19 *Leak*: Updates to Table 1 contain new language to establish that Table 1 is effective until June 30, 2024. The requirements of new Table 2 go into effect after June 30, 2024. Table 2 contains a new minor leak definition for components subject to Rule 4624. Components will have a minor gas leak threshold of 500 ppmv, and a major gas leak threshold of 1,000 ppmv or greater.

Table 1 – Leak in ppmv as Methane (Until June 30, 2024)	
	Leak
Component	1,000 and greater

Table 2 – Leak in ppmv as Methane (After June 30, 2024)		
	Major Leak	**Minor Leak**
Component	1,000 and greater	500 to less than 1,000

- 3.22 *Optical Gas Imaging (OGI)*: The District added a definition to include OGI. The new definition reads as follows:

  Optical Gas Imaging (OGI): *an instrument that makes emissions visible that may otherwise be invisible to the naked eye.*

- 3.27 *Process Drain*: New definition added for clarity to define a process drain. New section reads as follows:

  Process Drain: *any open portion of a non-continuous piping system, including open origination portion(s) of such a system used for collection and transport of liquids discharged from process vessels, spills, or other sources.*

- 3.30 *Tag*: New definition added to provide clarity on the identification of a leak. New definition reads as follows:

  Tag: *a piece of paper, metal, plastic or other suitable material that is attached to a component for the purpose of identification or other information.*

- 3.32 *True Vapor Pressure*: Update to definition to provide clarity and consistency across other District LDAR rules. Update to the definition reads as follows:

  True Vapor Pressure: *the equilibrium partial vapor pressure exerted by an organic liquid at actual storage temperature as determined by the applicable test methods specified in Section 6.3.*

- 3.33 *Unsafe-to-Monitor*: New definition added to address the components that would prevent the safe inspection or repair of a component. New definition reads as follows:

  Unsafe-to-Monitor: *a component installed at a location that would prevent the safe inspection or repair of a component as defined by OSHA standards or in provisions for worker safety stated in 29 CFR 1910.*

- 3.34 *Volatile Organic Compound*: Updated definition to provide consistency.

Section 4.0 – Exemptions

- 4.1 Updated language to provide clarity. Updated section reads as follows:

  The requirements of Section 5.0 of this rule shall not apply to organic liquid transfer facilities which transfer less than 4,000 gallons of organic liquids ~~in any one day~~ daily. The operator shall meet the applicable recordkeeping requirements of Section 6.1.1.

Section 5.0 – Requirements

- 5.9.3 *Repair Time*: The District created a table of the current repair times under Rule 4624.

Table 3 – Repair Time Periods	
Type of Leak	**Repair Time Period**
Liquid Leak	72 hours
Gas Leak	72 hours

- 5.9.4 *Leak Detection and Repair Inspection*: The District is proposing to phase out Section 5.9.4 to remove the option of LDAR inspection reverting to annual. All components subject to 4624 will require inspection in accordance with Section 5.9.1 of Rule 4624. This will establish quarterly inspections for all components subject to Rule 4624.

- 5.9.5 *Allowable Leaks*: The District is proposing new Section 5.9.5, effective after June 30, 2024, which provides an allowable number of minor leaks. This provides consistency across other District LDAR rules. Leaks falling under Table 4 of the proposed Rule are still subject to the leak repair timeframe of Rule 4624.

Table 4 – Number of Allowable Leaks after June 30, 2024	
Minor leaks	2.0% of number inspected
Major leaks	0

- 5.9.6 *Audio-visual Inspections*: New Section 5.9.6 establishes requirements to perform audio-visual inspection at least once every 24 hours for facilities that are visited daily. These inspections do not replace a quarterly LDAR inspection and further actions are needed if a leak is detected while performing an audio-visual inspection. Pipes shall also be inspected once every 12 months.

- 5.9.7 *Audio-visual Inspection*: New section requires operators to test leaks found under Section 5.9.6 with EPA Reference Method 21 within 24 hours, and requires the operator to repair leaks as directed in Section 5.9.3.

- 5.10 *Maintenance Requirements:* New section added to include requirements for tagging leaking equipment.

Section 6.0 – Administrative and Recordkeeping Requirements

- 6.1.4 *Record Retained and Request*: Replaced the word "or" with "and" to provide clarity of who has access to operator records.

- 6.1.6 *Inspection Log*: New sections 6.1.6.1 through 6.1.6.10 establish an inspection log regimen for inspections, tracking of leaking components, and records of calibration of detection instruments. This new section provides consistency across other District rules with LDAR programs.

- 6.3.8 *Test Method*: New section to clarify OGI observed leaks. New subsection 6.3.8.1 further defines procedures for leaks detected when using OGI. The new section reads as follows:

  All leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two (2) calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 3.

Section 7.0 – Compliance Schedule

- 7.1 Section deleted to remove outdated language.

- 7.2 Section deleted to remove outdated language.

III. ANALYSIS

A. Emission Reduction Analysis

In order to determine the emission reductions associated with the proposed changes, District staff queried the District Permit Services Database for all facilities impacted from the proposed changes, and data provided by CARB staff from surveys conducted in 2007, along with information provided by industry on affected components. Based on existing permitted limits, District staff calculated the PTE for each affected unit, and then, based on the proposed requirements and leak limits, calculated the percent

reduction that would be achieved through compliance with the proposed rule amendments.

For State Implementation Plan (SIP) purposes, the District applied the percent reduction achieved through compliance with the proposed rule changes to the baseline emissions inventory used in the District's *2022 Ozone Plan.* Based on these calculations, the SIP-creditable emission reductions estimated to be achieved from the proposed amendments to Rules 4401, 4409, 4455, 4623, and 4624 are illustrated in the table below, in tons per day (tpd) on an annual average basis.

Table 6 – SIP Emissions Reductions for 2024

Rules	% of Emissions Reduced at 500 ppmv	Tons/day of VOC reduced from CEPAM Data @ 500 ppmv
4401	19.9%	0.20
4409		
4455	12.8%	0.02
4623	28.7%	0.69
4624	15.6%	0.18
Total		**1.09**

Details of the District's emissions reduction analysis is contained in Appendix B of this staff report.

B. Cost Effectiveness Analysis

CH&SC Section 40920.6(a) requires the District to conduct both an absolute cost effectiveness analysis and an incremental cost effectiveness analysis of available emission control options before adopting each BARCT rule. The purpose of conducting a cost effectiveness analysis is to evaluate the economic reasonableness of the pollution control measure or rule. The analysis also serves as a guideline in developing the control requirements of a rule. Cost effectiveness will depend on the current level of controls, number of subject components, leak limits and final emission levels. Details of the cost effectiveness analysis is contained in Appendix C to this report.

C. Socioeconomic Analysis

State law requires the District to analyze the socioeconomic impacts of any proposed rule or rule amendment that significantly affects air quality or strengthens an emission limitation. Appendix D includes the socioeconomic impact analysis.

D. Environmental Impact Analysis

According to Section 15061 (b)(3) of the California Environmental Quality Act (CEQA) Guidelines, a project is exempt from CEQA if, "(t)he activity is covered by the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA." As such, substantial evidence supports the District's assessment that the rule amendment project will not have any significant adverse effects on the environment.

Furthermore, the rule amendment project is an action taken by a regulatory agency, the San Joaquin Valley Air Pollution Control District, as authorized by state law to assure the maintenance, restoration, enhancement, or protection of air quality in the San Joaquin Valley where the regulatory process involves procedures for protection of air quality. CEQA Guidelines §15308 (Actions by Regulatory Agencies for Protection of the Environment), provides a categorical exemption for "actions taken by regulatory agencies, as authorized by state or local ordinance, to assure the maintenance, restoration, enhancement, or protection of the environment where the regulatory process involves procedures for protection of the environment. Construction activities and relaxation of standards allowing environmental degradation are not included in this exemption." No construction activities or relaxation of standards are included in this rule amendment project.

Therefore, for all the above reasons, the rule amendment project is exempt from CEQA. Pursuant to Section 15062 of the CEQA Guidelines, District staff will file a Notice of Exemption upon Governing Board approval.

E. Rule Consistency Analysis

Pursuant to CH&SC §40727.2, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of the rule or regulation with corresponding elements of existing or proposed District and EPA rules, regulations, and guidelines that apply to the same source category. District staff have concluded that the proposed rules are neither in conflict with nor inconsistent with other District rules, or with federal policy, rule, or regulations governing the same source category. Appendix E includes further details on the District's rule consistency analysis.

F. Reasonably Available Control Technology (RACT) and Best Available Retrofit Control Technology (BARCT) Analyses

Sections 182(b)(2) and 182(f) of the federal Clean Air Act require ozone nonattainment areas to implement RACT for sources that are subject to CTG documents issued by EPA and for "major sources" of VOCs and NOx, which are ozone precursors. RACT can be defined as devices, systems, process modifications, or other apparatus or

techniques that are reasonably available, taking into account the necessity of imposing such controls in order to attain and maintain a national ambient air quality standard (NAAQS); the social, environmental, and economic impact of such controls; and alternative means of providing for attainment and maintenance of such a standard. These control techniques, which EPA defines in guidelines for limiting emissions from existing sources in nonattainment areas, are adopted and implemented for nonattainment areas by state analysis.

In September of 2017, the California State Legislature and Governor passed AB 617, Non-vehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants. One requirement of AB 617 is for air districts located in nonattainment areas to perform a BARCT analysis of their existing rules and regulations, and if applicable, propose an expedited schedule for revising rules found not meeting BARCT requirements. Most existing stationary sources in nonattainment areas such as the San Joaquin Valley have been subject to BARCT requirements since the 1980s. CH&SC Section 40406 defines BARCT as follows:

> *"Best Available Retrofit Control Technology (BARCT) is an air emission limit that applies to existing sources and is the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts by each class or category of source."*

Appendix F includes further details on the District's BARCT and RACT analyses.

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APPENDIX A

Summary of Significant Comments and Responses for Proposed Amendments to Rules 4401, 4409, 4455, 4623 and 4624

June 15, 2023

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SUMMARY OF SIGNIFICANT COMMENTS
DRAFT AMENDMENTS TO RULES 4401, 4409, 4455, 4623, and 4624
October 7, 2021

The District held a public workshop to present, discuss, and receive comments on the draft amendments to Rules 4401, 4409, 4455, 4623, and 4624 on October 7, 2021. Summaries of significant comments received during the public workshop and associated comment period are summarized below.

Comments were received from the following:

Amy Roth, E&B Natural Resources Management Corporation (E&B)
Jasmin Martinez, Central Valley Air Quality Coalition (CVAQ)
Scott Faulkenburg, EnviroTech (EnviroTech)
Juan Campos, California Resources Corporation (CRC)

1. **COMMENT:** A limit of 500 parts per million by volume (ppmv) for minor leaks is impractical for tanks. We recommend raising the limit of tank leaks or creating a separate leak limit from component leak limits. (E&B, CRC)

   RESPONSE: The District appreciates your comment. In support of the proposed amendments, the District conducted a comprehensive evaluation of technological feasibility, including a review of analogous local, state, and federal regulations, and have concluded that a 500 ppmv leak limit is a feasible and cost-effective level. In addition, Reasonably Available Control Technology (RACT) recommendations in the 2016 Control Techniques Guidelines (CTG) for Oil and Gas operations suggest 500 ppmv as the Leak Detection and Repair (LDAR) threshold. Analysis of emission reductions and cost-effectiveness at different leak thresholds is located in Appendix B and Appendix C of this staff report.

2. **COMMENT:** We recommend the removal of “small producer” exemptions in both Rule 4623 and Rule 4624. (CVAQ)

   RESPONSE: The District appreciates your comment. Rule 4624 is applicable to the processes and components associated with the transfer of organic liquids and does not include a “small producer” exemption. The proposed amendments to Rule 4623 will significantly enhance the applicability and stringency of the regulation beyond the existing stringent requirements, and will fully address state Best Available Retrofit Control Technology (BARCT) and federal RACT requirements and recommendations outlined by CARB and U.S. EPA. Additionally, Rule 4623 largely aligns with limited exemptions included in the State’s Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities Regulation (COGR). The District will continue to evaluate this source category for additional potential amendments in close coordination with CARB

and U.S. EPA through ongoing review of local, state (COGR), federal (New Source Performance Standards and CTG) requirements.

3. **COMMENT:** Is there any coordination between the District and the California Air Resources Board (CARB) regarding COGR? (EnviroTech, CRC)

RESPONSE: District staff have been working very closely with CARB staff in developing the proposed amendments to the District's rules in addition to following the development of the proposed COGR amendments to ensure as much consistency between the rules as possible. The District will continue to work with CARB as they consider potential additional revisions to the COGR in the future.

SUMMARY OF SIGNIFICANT COMMENTS
DRAFT AMENDMENTS TO RULES 4401, 4409, 4455, 4623, and 4624
March 10, 2022

The District held a public workshop to present, discuss, and receive comments on the draft amendments to Rules 4401, 4409, 4455, 4623, and 4624 on March 10, 2022. Summaries of significant comments received during the public workshop and associated comment period are summarized below.

Comments were received from the following:

David B. Nielsen, Kern Energy (Kern)
Scott Faulkenburg, Joe Selgrath, EnviroTech (EnviroTech)
Christine Zimmerman, Mike Kelly, Vector Environmental, (WSPA)
Theresa Geijer Shell (Shell)
Rock Zierman, (CIPA)
Lance Ericksen, Chevron (Chevron)
Bruce Faulkenhagen, (Faulkenhagen)

1. **COMMENT:** Are gauge hatches on tanks considered components under Rule 4623? (EnviroTech)

   RESPONSE: Under the proposed amendments, gauge hatches are considered components.

2. **COMMENT:** The District is proposing a 30-day extension for rig up operations to comply with LDAR requirements. Can more time be allotted if needed? (Faulkenhagen)

   RESPONSE: The District appreciates your comment. The current rule requires repairs to components be completed within 2-14 days of discovery depending on several factors (component type, leak concentration, etc.). However, due to the significant work required to replace/repair some equipment and oil and gas well issues that require contracting with a third-party rig-up operation, the District is allowing for an additional 30 days to complete the work and believes this to be a sufficient amount of time. This time period is also consistent with the State's COGR requirements.

3. **COMMENT:** We recommend a leak threshold of 5,000 ppmv rather than 500 ppmv for Rule 4623. (Kern, EnviroTech)

   RESPONSE: See District's response to comment 1 from the October 7, 2021 workshop.

4. **COMMENT:** We suggest the addition of language in Rule 4623 to allow for a breathing rate for pressure relief devices (PRDs). (Kern)

   RESPONSE: The District appreciates your comment, but there are no amendments proposed for Rule 4623 for PRDs or pressure-vacuum relief valves (PVRVs). The current language allows for breathing for PVRVs provided the equipment is designed and maintained in good working order and in accordance with manufacturer's instructions. This requirement is also consistent with the State's COGR requirements associated with PVRVs.

5. **COMMENT:** The repair time allowed for major gas and liquid leaks does not allow enough time to submit the Rule's required roof landing notification, which is currently five days, and then go on to degas the tank to the standard in the rule. We suggest reducing the notification time to the District from five days to three days. (Kern)

   RESPONSE: The District appreciates the comment and is proposing to change the notification period to three days.

6. **COMMENT:** The District should consider preventative maintenance (tanks, floating roof tank fittings, rim seals, etc.) requirements similar to Bay Area Air Quality Management District (AQMD) Regulation 8, Rule 5 and South Coast AQMD Rule 463 where they provide limited exemptions from the requirements of the rule while performing pro-active maintenance. This provision would encourage tank operators to perform preventative maintenance without taking a tank out of service and would eliminate variance petitions. (Shell, Kern, WSPA)

   RESPONSE: The District appreciates your comment but is not proposing to make any changes to the current rule requirements for preventative maintenance. The purpose of the rule amendments are to address BARCT and RACT requirements. The District will consider potential amendments to address preventative maintenance in future amendments.

7. **COMMENT:** The Governing Board hearing should be held 60 days after the cost-effectiveness analysis is posted to allow time for review and comments. (CIPA, WSPA)

   RESPONSE: The District appreciates your comment and has been working on the proposed amendments for three years and has shared cost-effectiveness estimates in a number of presentations throughout the rule amendment process, including public workshops and meetings. Additionally, the District posted the entire draft cost-effectiveness analysis on April 26, 2023, which is nearly 60 days prior to the hearing. The District has incorporated all available information in the publically presented cost-effectiveness analysis.

8. **COMMENT:** The current cost per ton of volatile organic compound (VOC) reduction is significantly higher than the District's Best Available Control Technology (BACT) threshold and the District's cost-effectiveness for the proposed amendments should not exceed the BACT threshold. (Chevron, WSPA)

   RESPONSE: The District appreciates your comment; however, BARCT cost-effectiveness cannot be compared to the District's BACT threshold. The District does not have an established BARCT cost-effectiveness threshold. BARCT is defined in the California Health and Safety Code § 40406 as an air emission limit that applies to existing sources and is the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts by each class or category of source. Based on this definition, recent rules that the District has adopted, and additional requirements including RACT, the cost-effectiveness of the proposed amendments are within the acceptable range. In addition, the socioeconomic analysis, included in Appendix D, did not indicate significant impacts to the industry based on the estimated costs for the proposed amendments.

9. **COMMENT:** Open-ended lines should not be considered automatic violations in the rules. (WSPA)

   RESPONSE: The District appreciates your comment and respectfully disagrees. Under District regulations and consistent with EPA RACT requirements, open-ended lines or open-ended valves must be equipped with a cap, blind flange, plug, or second valve to seal the open end at all times, except during operations requiring process fluid flow through the open-ended line or valve.

SUMMARY OF SIGNIFICANT COMMENTS
DRAFT AMENDMENTS TO RULES 4401, 4409, 4455, 4623, and 4624
April 17, 2023

The District held a public workshop to present, discuss, and receive comments on the draft amendments to Rules 4401, 4409, 4455, 4623, and 4624 on April 17, 2023. Summaries of significant comments received during the public workshop and associated comment period are summarized below.

Comments were received from the following:

Lance Ericksen, Chevron (Chevron)
Valerie Muller, Crimson Pipeline (Crimson)
Gabe Castro, Kern Energy (Kern)
Theresa Geijer, Shell (Shell)
David Rosenkrantz, Discus Engineering Products (Discus)
Christine Zimmerman, Western States Petroleum Association (WSPA)

1. **COMMENT:** What is the benefit of Optical Gas Imaging (OGI) in the proposed rules if it cannot replace U.S. Environmental Protection Agency (EPA) Method 21 during quarterly LDAR inspections? (Chevron, WSPA)

   RESPONSE: The District appreciates your comment, and has included provisions for the use of OGI as a potential screening tool for locating leaks, especially in hard to reach areas. These provisions are consistent with the State's COGR requirements and provides clarity for leaks observed with such devices.

2. **COMMENT:** What are the main changes to the Voluntary Tank Preventive Inspection and Maintenance, and Tank Interior Cleaning Program? (Chevron)

   RESPONSE: The District appreciates your comment and is proposing to phase out the Voluntary Tank Preventive Inspection and Maintenance and Tank Interior Cleaning Program. The District is proposing to require that tanks comply with the Storage Tank and Interior Cleaning Requirements in Rule 4623, as specified in Section 5.7.5.

3. **COMMENT:** The District should consider preventative maintenance (tanks, floating roof tank fittings, rim seals, etc.) requirements similar to Bay Area Air Quality Management District (AQMD) Regulation 8, Rule 5 and South Coast AQMD Rule 463 where they provide limited exemptions from the requirements of the rule while performing pro-active maintenance. This provision would encourage tank operators to perform preventative maintenance without taking a tank out of service and would eliminate variance petitions. (Crimson, Shell, Kern)

RESPONSE: See District's response to comment 6 from the March 10, 2022, workshop.

4. **COMMENT:** We request additional time to submit an Authority to Construct (ATC) and more time for implementation of a vapor control system since it takes a considerable amount of time to plan, design and install such equipment. (Chevron, Kern)

   RESPONSE: The District appreciates your comment and has changed the compliance deadline for installation of a new vapor control system to 12 months after the issuance of an ATC and the ATC submittal deadline has been moved to March 31, 2024.

5. **COMMENT:** We suggest adding language in Rule 4623 to develop an allowable breathing rate for PRDs to avoid bulges or collapses of a tank holding organic liquid. (Kern)

   RESPONSE: See the District's response to comment 4 from the March 10, 2022 workshop.

6. **COMMENT:** In Rules 4623, 4624, and 4455, the leak threshold is proposed to be lowered to 500 ppmv. This is a drastic reduction in the leak rate. The District should consider higher limits. (Kern)

   RESPONSE: See District's response to comment 3 from the March 10, 2022, workshop.

7. **COMMENT:** The repair time allowed for major gas and liquid leaks does not allow enough time to submit the Rule's required roof landing notification, which is currently 5 days, and then go on to degas the tank to the standard in the rule. This leaves the facility in non-compliance. We suggest reducing the notification time to the District from five days to one day. (Kern)

   RESPONSE: See District's response to comment 5 from the March 10, 2022, workshop.

8. **COMMENT:** Rule 4623 and Rule 4624 contain a requirement for audio-visual inspection of all hatches, PVRVs, PRDs, and pump seals at least every 24 hours. Furthermore, leaks discovered during these inspections must be tested using EPA Method 21 within 24 hours. This requirement may increase costs due to constant monitoring and requirement to buy new equipment. (Kern)

RESPONSE: The District appreciates your comment; however, as LDAR requirements are being added to Rules 4623 and 4624, the District included requirements for audio/visual inspections from other District Rules (Rules 4401, 4409, and 4455) to allow for consistency across all the rules. The District considered increased costs associated with LDAR requirements in the proposed rulemaking, as included in Appendix C.

9. **COMMENT:** In Rule 4623**,** Section 6.2.1.1.6 states that an operator must collect samples of crude oil and produced water upstream of the oil/water/gas separator tank, and must maintain a sketch or diagram of the separator and tanks system depicting where the samples were collected. Can the District provide more details why this requirement was placed in the rule? (Kern, WSPA)

RESPONSE: The District appreciates your comment, and the addition of the testing requirements is consistent with COGR and allows the District to verify that the sample is being taken at the proper location. Testing is conducted by gathering pressurized liquid samples upstream of a separator and tank system. The intent is to replicate flash emissions from a separator and tank system open to the atmosphere. Therefore, samples must be gathered upstream of the system before emissions can flash from the liquid.

10. **COMMENT:** Can the District amend the inspection log requirements to allow for electronic documentation? (Kern)

RESPONSE: The District appreciates your comment. Section 6.3.9 does not specify a certain way of maintaining an inspection log, and allows for flexibility of recordkeeping, including maintaining electronic recordkeeping logs.

11. **COMMENT:** In Rule 4455, the removal of Section 4.2.8 will create 24,000 new components to inspect per year. Typically, half-inch fittings are compression fittings and are leak free by design. We suggest to reconsider the removal. (Kern)

RESPONSE: The District appreciates your comment; however, EPA's 2016 CTG does not include an exemption for half-inch fittings. CARB was found deficient in for exempting half-inch fittings, so they are taking action to remove this exemption from COGR because the 2016 CTG. Since Rules 4401, and 4409 are subject to the 2016 CTG, the District is also removing the exemptions. To provide for consistency across all District rules, the District is also removing the exemption from Rule 4455.

12. **COMMENT:** In Rule 4455, the major leak repair time has decreased from two days down to one day. This will make operators prioritize leaks above all other work requests in the maintenance system. This could result in the neglect of proactive preventative maintenance. (Kern)

RESPONSE: The District appreciates your comment; however, based on a review of other air District rules, the District determined that a one day repair period is considered BARCT for major leaks.

13. COMMENT: Does the audio-visual inspection apply to pipes that transfer organic liquid from storage tanks to loading racks? If so, at what point does a pipe fall under the Rule 4624 requirements? Additionally, the inspection requirement should be changed to once per day in order to consistently meet with a 24-hour deadline. Many sites are staffed at some point seven days per week, but not 24 hours per day. For these sites, there can be periods of more than 24 hours with no one at the facility. (Shell)

RESPONSE: The District appreciates your comment. The audio-visual inspection requirements apply to pipes that transfer organic liquid from storage tanks to the loading rack. Requirements of Rule 4624 begin at the organic liquid pump to the vessel/truck through the vapor return line and back to the organic storage tank or destruction device (as applicable). Audio-visual inspections are required once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours.

14. COMMENT: Rule 4623 Section 5.4.1 requires mechanical shoe seals to extend 18 inches above the product level. Current EPA and API standards are not reflective of the District's requirement. (Discus)

RESPONSE: The District appreciates your comment and has amended Section 5.4.1 to allow mechanical shoe seals to extend a minimum of six inches above the product level. The District found this to be consistent with requirements in other District rules. The District determined there is no change in emissions from this amendment.

15. COMMENT: The existence of an open-ended line should not trigger an automatic violation for rules 4401 and 4409. There should be a reasonable period of time to repair an open-ended line. (WSPA)

RESPONSE: See the District's response to comment 11 from the March 10, 2022, workshop.

16. **COMMENT:** For Rule 4401, the leak thresholds for PRDs should be increased from 400 ppmv to 500 ppmv. This change would align the definition of a minor gas leak and lessen confusion when conducting inspections. (WSPA)

RESPONSE: The District appreciates your comment; however, this is an existing limit in the rule, and increasing the limit to 500 ppmv would result in the back-sliding of requirements. Therefore, no changes will be made to this limit.

17. **COMMENT:** For Rules 4401 and 4409, the exemption for streams containing 10% or less VOC should be retained. Elimination of this exemption would subject these components to duplicative LDAR requirements, imposed via the District as well as COGR. (WSPA)

RESPONSE: The District appreciates your comment. Under Rule 4401, components subject to Section 4.7 are currently only exempt from operator LDAR inspections, but are subject to the leak standards of the Rule. The removal of Section 4.7 will require operators to conduct LDAR inspections and re-inspections under Rule 4401, which operators are already conducting under COGR. Therefore, removal of this exemption will not result in a significant change to operators' LDAR programs. For Rule 4409, the District is no longer proposing to eliminate "gas/vapor" from Section 4.2.10 because it would create duplicative requirements with COGR.

18. **COMMENT:** In Rule 4623, the District is proposing to revise the TVP used as criteria for qualifying for an exemption from several of the rule requirements. The exemption threshold would be lowered from 0.5 TVP to 0.1 TVP. The change will extend the rule requirements to tanks that contain organic liquids that do not readily volatize. The definition should differentiate between a "Minor Liquid Leak" and a "Major Liquid Leak". (WSPA)

RESPONSE: The District appreciates your comment; however, the District is not proposing to amend the rule to differentiate between a major and minor liquid leak at this time and is proposing to maintain one liquid leak standard.

19. **COMMENT:** The District should include an exemption for PRDs, pumps, and compressors where vapors are routed to a closed vent system. (WSPA)

RESPONSE: The District appreciates your comment; however, there is a potential for the identified components to leak. Therefore, these components will continue to be subject to LDAR requirements.

20. **COMMENT:** In Rule 4623, Section 5.9.1 should be revised to recognize that leaking components discovered during a District inspection that have been properly tagged by the operator and are awaiting repair within the allowable repair period, do not constitute a violation of the rule. (WSPA)

RESPONSE: The District appreciates your comment and Rule 4623 defines what constitutes a violation on leaking components discovered during a District inspection. If a component is properly tagged and repaired within the allowable timeframe, it is not considered a violation as long as the leak does not exceed 10,000 ppmv, or the allowable leak threshold found in Table 8 of the proposed rule.

21. **COMMENT:** In Rule 4624, the term “major leak” is used in the existing regulation, but it is not defined. The District is now proposing to revise the regulation in such a manner as to effectively define a major leak as 1,000 ppmv (proposed Table 2). The definitions of “major leak” should be consistent with that definition proposed in the other LDAR rules, where a major leak is defined to be greater than 10,000 ppmv (as methane). (WSPA)

Response: The District appreciates your comment. Current Rule 4624 includes a leak threshold of 1,000 ppmv or greater. The District is proposing a new limit of 500 ppmv. To differentiate between these two limits, the District is characterizing the 1,000 ppmv leak as a “major leak” and 500 ppmv as a “minor leak” for the purposes of Rule 4624 only.

22. **COMMENT:** The District's proposed cost-effectiveness for the rules go beyond BARCT requirements. (WSPA)

Response: See the District’s response to comment 8 from the March 10, 2022, workshop.

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APPENDIX B

Emission Reduction Analysis
For Proposed Amendments to Rules 4401, 4409, 4455, 4623, & 4624

June 15, 2023

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EMISSIONS REDUCTION ANALYSIS FOR PROPOSED RULES 4401, 4409, 4455, 4623, and 4624

I. SUMMARY

The San Joaquin Valley Air Pollution Control District (District) committed to amend Rules 4401, 4409, 4455, 4623, and 4624 as part of the Best Available Retrofit Control Technology (BARCT) analysis pursuant to Assembly Bill (AB) 617 requirements, in addition to commitments from the *2022 Plan for the 2015 8-Hour Ozone Standard* (*2022 Ozone Plan*). This appendix details the calculations and assumptions used to estimate the volatile organic compound (VOC) emission reductions associated with the proposed amendments.

Table B-1 presents a summary of the total emission reductions in tons per day (tpd) of VOC for each rule and for the entire project. Section II includes a detailed emission reductions analysis.

Table B-1 Total VOC Reductions at 500 ppmv

Rule	VOC Reduction at 500 ppmv (tpd)
4401	0.073
4409	0.293
4455	0.00037
4623	0.210
4624	0.021
Total	**0.597**

II. EMISSION REDUCTION ANALYSIS

This section of the report outlines the procedures used to calculate the current emissions and the estimated emission reductions associated with the proposed amendments to Rules 4401, 4409, 4455, 4623, and 4624.

This analysis applied Equation 1 to the components affected by Rules 4401, 4409, 4455, 4623, and 4624 to calculate potential emissions from each facility at the proposed limit(s). The District used Equation 1 to calculate the percent reduction for each pollutant from affected categories by calculating the percent difference between the current potential emissions and potential emissions at the proposed amended limit(s).

$$\%_{Reduced} = \frac{(\sum E_{Current} - \sum E_{Proposed})}{\sum E_{Current}} \quad \text{(Equation 1)}$$

Where:

$\%_{Reduced}$ = percent reduction;
$E_{Current}$ = current potential emissions; and
$E_{Proposed}$ = the potential emissions at proposed limits.

The District calculated the emission reductions by multiplying the current potential emissions in Table B-2 by the calculated percent reductions determined with Equation 2, as follows:

$$ER = EI \times \%_{Reduced} \quad \text{(Equation 2)}$$

Where:

ER = emission reduction;
EI = emission inventory; and
$\%_{Reduced}$ = calculated percent reductions, per Equation 1.

A. Affected Components

Table B-2 Summary of VOC Emission Reductions @ 500 ppmv

Rules	Number of Components	Current VOC Emissions tons/day	Emissions at Proposed 500ppmv tons/day	Estimated VOC Reductions tons/day	Estimated VOC Reductions Percentage
4401	893,392	0.34	0.27	0.07	21.5%
4409	1,511,035	1.50	1.21	0.29	19.5%
4455	1708	0.0029	0.0025	0.0004	12.8%
4623	179,052	0.73	0.53	0.21	28.7%
4624	40,001	0.13	0.11	0.02	15.6%
Total	**2,625,188**	**2.70**	**2.12**	**0.59**	**21.9%**

*estimated reductions are rounded integers

The components identified in the emissions reduction are sourced from the California Air Resources Board's (CARB) 2007 Oil and Gas Industry Survey Results[1], and District information from Operator Management Plans.

B. Emission Reduction Calculation Methodology

An emissions factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors express the weight of pollutant divided by a unit weight,

[1] State of California, California Environmental Protection Agency, Air Resources Board. "2007 Oil and Gas Industry Survey Results. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/2020-04/finalreport_1.pdf

volume, distance, or duration of the activity emitting the pollutant (e.g., pounds of VOC emitted per hour). Such factors facilitate estimation of emissions from various sources of air pollution. In most cases, these factors are averages of all available data of acceptable quality, and are representative of long-term averages for all facilities in the source category (i.e., a population average).

The calculation of VOC emissions for the current rules and the emission reductions are derived from the methodology established in Section 5-7 and Appendix A of EPA's Protocol for Equipment Leak Emission Estimates.[2] EPA's protocol contains equations for calculating average leak rates for each type of component and type of service. Additionally, EPA's protocol document outlines a method for predicting the leak rate after the implementation of Leak Detection and Repair (LDAR) programs. Equation 3 determines the Average Leak Rate of a component based on the ppmv limit and type of service (gas or liquid).

$$ALR = (LR * LkFrac) + ELTC \quad \text{(Equation 3)}$$

Where,
ALR: Average Leak Rate in kilograms per hour
LR: Leak rate in kilograms per hour
LkFrac: Leak Fraction
ELTC: Equipment Leak Type Constant

$$EM = ALR * Components \quad \text{(Equation 4)}$$

Where,
EM: Emissions in kilograms per hour
ALR: Average Leak Rate
Components: Number of components in service

[2] EPA. Protocol for Equipment Leak Emission Estimates. EPA 453/R-95-017. November 1995. Retrieved from https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

Table B-3 Equations for Calculating Initial Average Leak Rate – From EPA 453/R-95-017, Table 5-7

Average Leak Rate Rules at 10,000 ppmv For Gas Services	
Components	**Gas**
Valves	0.093 * (LkFrac) + 0.0000250
Pumps/Compressors	0.074 * (LkFrac) + 0.0003500
Others	0.089 * (LkFrac) + 0.0001200
Connectors	0.026 * (LkFrac) + 0.0000100
Flanges	0.082 * (LkFrac) + 0.0000057
Average Leak Rate for Rules at 2,000 ppmv for Gas Services	
Components	**Gas**
Valves	0.083 * (LkFrac) + 0.0000140
Pumps/Compressors	0.052 * (LkFrac) + 0.0002300
Others	0.066 * (LkFrac) + 0.0000450
Connectors	0.020 * (LkFrac) + 0.0000085
Flanges	0.059 * (LkFrac) + 0.0000026

Average Leak Rate at 1,000 ppmv for Gas Services and Liquid Services		
Components	**Gas**	**Liquid**
Valves	0.076 * (LkFrac) + 0.0000110	0.069 * (LkFrac) + 0.0000120
Pumps/Compressors	0.052 * (LkFrac) + 0.0002300	0.079 * (LkFrac) + 0.0001500
Others	0.061 * (LkFrac) + 0.0000310	0.058 * (LkFrac) + 0.0000440
Connectors	0.018 * (LkFrac) + 0.0000080	0.021 * (LkFrac) + 0.0000083
Flanges	0.051 * (LkFrac) + 0.0000180	0.046 * (LkFrac) + 0.0000012

Table B-4 Equations for Calculating Average Leak Rate at Proposed 500 ppmv for Gas and Liquid Components

Components	Gas	Liquid
Valves	0.070 * (LkFrac) + 0.0000091	0.059 * (LkFrac) + 0.0000094
Pumps/Compressors	0.027 * (LkFrac) + 0.0001100	0.071 * (LkFrac) + 0.0000790
Others	0.055 * (LkFrac) + 0.0000180	0.053 * (LkFrac) + 0.0000340
Connectors	0.016 * (LkFrac) + 0.0000077	0.016 * (LkFrac) + 0.0000077
Flanges	0.043 * (LkFrac) + 0.0000011	0.037 * (LkFrac) + 0.00000094

LkFrac = Leak Fraction

Using Equation 3, the Average Leak Rate can be determined for each component type and service type. The emissions across all components can be determined using Equation 4 to multiply the Average Leak Rate by the total number of components. To determine the VOC Baseline Emissions, total organic carbon (TOC) emissions from the components are calculated using the average TOC emission factors from Table 2-4 of

EPA 453/R-95-017. District calculations indicate that 19% of all TOC is VOC. Table B-5 presents the emissions reduction comparison at current leak limits versus the proposed 500 ppmv leak limit. Table B-6 shows the calculated VOC emission reductions.

Table B-5 Emissions Comparison at Current Leak Limits and 500 ppmv

Rule	Total Components	Current Emissions		Emissions @ 500 ppmv	
		kg/hr[3]	tons/year[4]	kg/hr[5]	tons/year[6]
4401*	893,392	12.9	125	10.14	97.9
4409	1,511,035	56.9	549	45.77	442.0
4455	1,708	0.11	1.05	0.10	1.05
4623*	179,052	27.7	267	20.04	190.4
4624	40,001	5.09	49	4.29	41.5
Totals	**2,625,188**	**102.6**	**991**	**80.35**	**773**

*Majority component emissions reduction were calculated from 1,000 ppmv to 500 ppmv as most components were subject to COGR, prior to the rule amendment.

Table B-6 Emissions Reduction of VOC

Rule	Reductions tons/year VOC[7]	Reductions tons/day VOC[8]
4401	26.8	0.073
4409	107.0	0.293
4455	0.135	0.00037
4623	76.8	0.210
4624	7.7	0.021
Total	**218.4**	**0.597**

*Reductions are presented as rounded integers

C. SIP Credit from Proposed Rules

Table B-5 includes the potential current emissions for permitted sources in the San Joaquin Valley. However, in order to determine the emission reductions for the State Implementation Plan, the District normalized the emission reductions to the planning inventory. Table B-7 summarizes the emission inventory codes (EICs) associated with the District's LDAR rules.

[3] Current Emissions (kg/hr) = (ALR) x (% of VOC in TOC)
[4] Current Emissions (tpy) = (emissions in kg/hr) x (lbs/kg ratio) x (yr/hr ratio) x (tons/lbs ratio)
[5] Emissions at 500 ppmv (kg/hr) = (ALR) x (% of VOC in TOC)
[6] Emissions at 500 ppmv (tpy) = (emissions in kg/hr) x (lbs/kg ratio) x (yr/hr ratio) x (tons/lbs ratio)
[7] Emissions Reduction (tpy)= (Current emissions) – (Emissions at 500 ppmv)
[8] Emissions Reduction (tpd) = (tpy)/365

Table B-7 List of EICs for Rules 4401, 4409, 4455, 4624, and 4624

Rules	EICs	EIC Summary
4401 & 4409	310-302-0110-0000; 310-302-1600-0000; 310-304-1600-0000; 310-302-0100-0000 310-304-0100-0000; 310-316-0110-0000; 310-306-1600-0000; 310-308-1600-0000 310-308-0110-0000; 310-303-0100-0000; 310-304-0110-0000; 330-302-1600-0000 310-310-0110-0000; 310-310-1600-0000; 310-316-1600-0000; 310-306-0110-0000 310-310-1600-0000; 330-304-1600-0000; 310-352-0100-0000; 310-356-0110-0000 310-303-1600-0000; 310-316-0100-0000; 330-306-1600-0000	Fugitive losses from oil and gas production
4455	320-302-0010-0000; 320-304-0010-0000; 320-306-0010-0000 320-316-0010-0000; 320-308-0010-0000	Fugitive losses from petroleum refining
4623	310-326-1600-0000; 310-328-1600-0000; 310-995-1600-0000; 310-322-1600-0000 310-326-2000-0000; 310-328-1420-0000; 310-328-3174-0000; 320-322-1420-0000 320-324-1600-0000; 320-328-0410-0000; 320-326-1610-0000; 330-322-1600-0000 330-326-1120-0000; 330-328-1120-0000; 330-330-1120-0000; 320-326-1000-0000 320-326-1214-0000; 320-326-1410-0000; 310-324-1100-0000; 310-326-2026-0000 310-328-1610-0000; 310-328-3220-0000; 320-322-1600-0000; 320-326-0410-0000 320-328-1120-0000; 330-321-1000-0000; 330-322-1610-0000; 330-326-1130-0000 330-328-1130-0000; 330-330-1130-0000; 320-326-1610-0000; 320-328-1000-0000 320-328-1110-0000; 310-324-1600-0000; 310-326-3220-0000; 310-328-2000-0000 310-328-4998-0000; 320-322-1610-0000; 320-326-1000-0000; 320-328-1130-0000 330-321-1410-0000; 330-324-1000-0000; 330-326-1210-0000; 330-328-1222-0000 330-330-1420-0000; 320-328-1214-0000; 320-328-1410-0000; 320-328-1610-0000 310-325-0100-0000; 310-326-4998-0000; 310-328-2026-0000; 310-995-1600-0000 320-324-1000-0000; 320-326-1110-0000; 320-328-1530-0000; 330-322-1000-0000 330-324-1224-0000; 330-326-1410-0000; 330-328-1410-0000; 430-328-7006-0000 330-326-1110-0000; 330-326-1420-0000; 330-328-1000-0000; 310-326-1000-0000 310-328-1000-0000; 310-328-3000-0000; 320-322-1000-0000; 320-324-1100-0000 320-326-1130-0000; 320-328-3202-0000; 330-322-1214-0000; 330-324-1420-0000 330-326-1600-0000; 330-328-1420-0000; 330-328-1110-0000; 330-328-1600-0000 330-328-1610-0000; 310-326-1420-0000; 310-328-1110-0000; 310-328-3033-0000 320-322-1130-0000; 320-324-1110-0000; 320-326-1530-0000; 320-328-3220-0000 330-322-1224-0000; 330-324-1600-0000; 330-326-1610-0000; 330-328-1600-0000 430-328-7006-0000; 310-326-1610-0000; 310-328-1130-0000; 310-328-3156-0000 320-322-1214-0000; 320-324-1224-0000; 320-326-3202-0000; 320-322-1000-0000 330-322-1420-0000; 330-326-1000-0000; 330-326-3000-0000; 330-328-1610-0000	Fugitive losses from organic liquid storage tanks
4624	330-302-0010-0000; 330-995-0110-0000; 330-304-0010-0000; 330-308-0110-0000 330-384-1130-0000; 330-995-0010-0000; 330-316-0010-0000; 330-318-0110-0000 330-316-0010-0000; 330-995-1100-0000; 330-316-1600-0000; 330-332-1000-0000 330-338-0010-0000; 330-382-1130-0000	Fugitive losses from petroleum marketing

The District calculated the emission reductions by multiplying the current potential emissions defined in Table B-2 by the calculated percent reductions determined with Equation 2, as follows:

$$ER = EI \times \%_{Reduced}$$

Where:

ER = emission reduction;
EI = emission inventory; and
$\%_{Reduced}$ = calculated percent reductions, per Equation 2.

Table B-8 includes the total VOC emissions from the EICs listed above.

Table B-8 Annual Average 2024 VOC Emission Inventory from Rules 4401, 4409, 4455, 4623, and 4624 (tpd)[9]

Rules	Tons/day
4401 and 4409	1.015
4455	0.147
4623	2.398
4624	1.166
Total	**4.725**

To determine the emission reductions achieved for SIP purposes, the District multiplied the percent reductions from Table B-2 by the planning inventory in Table B-8. Table B-9 presents the results of this calculation.

Table B-9 Emission Reductions from Proposed Amendments in Implementation Years (tons per day)

Rules	% of Emissions Reduced at 500 ppmv	Tons/day of VOC reduced from CEPAM Data @ 500ppmv
4401 and 4409	19.9%	0.20
4455	12.8%	0.02
4623	28.7%	0.69
4624	15.6%	0.18
Total		**1.09**

[9] CEPAM Ozone SIP 2019 v1.04

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APPENDIX C

Cost-Effectiveness Analysis for Proposed Amendments to Rules 4401, 4409, 4455, 4623 and 4624

June 15, 2023

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COST-EFFECTIVENESS ANALYSIS FOR PROPOSED RULES 4401, 4409, 4455, 4623, and 4624

I. SUMMARY

The California Health and Safety Code (CH&SC) Section 40920.6(a) requires the San Joaquin Valley Air Pollution Control District (District) to conduct both an absolute cost-effectiveness analysis and an incremental cost-effectiveness analysis of available emission control options before adopting Best Available Retrofit Control Technology (BARCT) rules. The purpose of conducting a cost-effectiveness analysis is to evaluate the economic reasonableness of the pollution control measure or rule. The analysis also serves as a guideline in developing the control requirements of a rule.

Absolute cost-effectiveness (ACE) is the added annual compliance cost to meet the proposed rule's requirements, in dollars per year, divided by the emission reduction achieved in tons of pollutant reduced per year.

Incremental cost-effectiveness (ICE) is intended to measure the change in costs (in $/year) and emissions reductions (in tons reduced/year) between two progressively more effective control options or technologies. ICE compares the differences in costs and the differences in emissions reductions of candidate control options. ICE does not reveal the emission reduction potential of the control options. Unlike the ACE analysis that identifies the control option with the greatest emission reduction, ICE does not present any correlation between emissions reductions and cost-effectiveness. Therefore, the relative values produced in the ICE analysis and the ACE values are not comparable and cannot be evaluated in the same way as absolute cost-effectiveness numbers.

The results of the cost-effectiveness analysis for the proposed amendments of Rules 4401 4409, 4455, 4623, and 4624 are summarized in Table C-1. The cost-effectiveness is analyzed by District staff and includes cost information provided by the California Air Resources Board (CARB), industry vendors, and the Western States Petroleum Association (WSPA). As shown in Table C-1, the estimated compliance cost ranges $28,257 per year to $7.4 million per year per rule and the overall cost-effectiveness ranges from $19,289 per ton of VOC emissions reduced per year to $209,708 per ton of VOC emissions reduced per year for the proposed rule amendments. The average cost-effectiveness for all rules is $59,170 per ton of VOC reduced per year.

Table C-1 Cost-Effectiveness Summary for Proposed Amendments

Rule	Cost Increase $/year	One time Equipment Cost	VOC Emissions Reduction tons/year	Cost-Effectiveness $/ton VOC reduced*
4401	$3,814,894		27	$142,424
4409	$7,432,341		107	$69,436
4455	$28,257		0.13	$209,708
4623	$1,187,083	$312,900	77	$19,537
4624	$148,120		8	$19,289
Total	**$12,610,696**	**$312,900**	**218.42**	**$59,170**

- Values are subject to rounding

Alternative Leak Limits Evaluated

As shown in the staff report, the District explored several leak limits in the rule amendment process. The District conducted a cost-effectiveness analysis for these leak limits, shown below, and found that the current proposal of 500 ppmv was the most cost effective for the commensurate emissions reduction compared to 100 ppmv. A 1,000 ppmv leak limit was not considered because it is not consistent with the Reasonably Available Control Technology recommendations in EPA's 2016 Control Techniques Guidelines for oil and natural gas.

Table C-2 Cost and Cost-Effectiveness for Alternative Leak Limits Evaluated

Throughput Limit	Emission Reductions VOC tons/yr	Cost at 500 ppmv Rule	Cost-effectiveness $/ton VOC
1,000 ppmv	67	$2,554,461	$43,033
500 ppmv	218	$12,610,696	$59,744
100 ppmv	245	$27,544,366	$103,286

Comparison of Current Emission Limits and Proposed Emission Limits

Based on CARB data, and current District permits, an estimated total of 2,625,188 components will be impacted by the proposed rule amendments. A summary of these components and their current emission limits are shown in Table C-3.

Table C-3 Summary of Components and Emission Leak Limits

Rule	Total Components	Current Emission Limits	Proposed Emission Limits
4401	893,392	Gas: 2,000 ppmv VOC	Gas: 500 ppmv
4409	1,511,035	Gas: 2,000 ppmv VOC Liquid: 1,000 ppmv VOC	Gas: 500 ppmv Liquid: 500 ppmv
4455	1,708	Gas: 1,000 ppmv VOC *(Pumps, Compressors, and Other)*	Gas: 500 ppmv *(Pumps, Compressors, and Other)*
4623	71,621*	Gas: 10,000 ppmv VOC	Gas: 500 ppmv
4624	40,001	Gas: 1,000 ppmv VOC	Gas: 500 ppmv
Total	**2,625,188**		

**Pre-rule amendment components subject to District rule*

II. COST-EFFECTIVENESS ANALYSIS PROCEDURE

To illustrate the cost-effectiveness of complying with the proposed limits, the District's analysis provides varying cost-effectiveness values depending on potential for a component to leak, the cost of more frequent Leak Detection and Repair (LDAR) inspections, and the eventual cost to replace leaking pieces of equipment in operation. The actual compliance costs and cost-effectiveness values depend on several factors such as the type of unit, operating conditions, and the emission limits for the unit.

District staff used cost information from stakeholders to conduct a cost-effectiveness analysis of the proposed leak limits, for Rules 4401, 4409, 4455, 4623, and 4624. Specifically, the data used in the analysis came from the following sources:

1. California Air Resources Board (CARB)
2. Western States Petroleum Association (WSPA)
3. Industry vendors

Cost information submitted to the District is used to establish the costs found in Tables C-4 through C-11.

A. Absolute Cost-Effectiveness Formula

ACE examines the cost of reaching the proposed emission limits using the current emissions as a baseline. Cost-effectiveness is calculated as the added annual cost ($/year) of a technique, in this case, lowering the minor leak emission limit, by dividing by the emissions reductions achieved (in tons of VOC reduced/year). The annual costs include capital equipment replacement costs, the cost of performing LDAR inspections, and the repair cost for affected components.

The absolute cost-effectiveness is as follows:

1. Determine an equivalent equipment replacement cost using a capital recovery factor based on current market values for components affected in each rule.
2. Determine the equivalent annual equipment repair cost for equipment that need more than a simple “quick fix” repair without the need to replace the equipment based on current market rates.
3. Determine the equivalent annual cost to perform LDAR requirements on all components subject to Rules 4401, 4409, 4455, 4623, and 4624.
4. Calculate the total annual cost by adding the costs calculated in Step 1, 2, and Step 3.
5. Calculate the emission reduction in tons/year. Appendix B provides a detailed explanation of the calculations performed to determine the emission reductions for the potential rule limits.
6. Calculate the absolute cost-effectiveness by dividing the total annual cost in Step 3 by the emissions reduction in Step 5.

B. Incremental Cost-Effectiveness Formula

ICE provides the additional cost for further controlling a component from the proposed limit to the lowest possible level. Costs are evaluated similarly to absolute costs, but are only calculated for the controls and reductions beyond what is required to comply with the rule. ICE does not reveal the emission reduction potential of the control options, but examines the more stringent options that were not considered cost effective. Due to the increased costs and marginal emission reductions, the ICE calculations typically show a higher cost-effectiveness than the absolute cost-effectiveness values, and are therefore not directly comparable.

The incremental cost-effectiveness of a control is calculated as follows:

1. Identify the complying control options appropriate for the existing equipment.
2. Estimate the annual average cost of each control option by using Steps 1 to 3 of the ACE calculation method.
3. Calculate the potential emission reduction for each control option. The potential emission reductions are the difference between the current emissions and the potential emissions using the new requirements.

For the ICE analysis, the emission reduction is the difference between the current rule emission limits to the proposed emission limits.

III. ABSOLUTE COST-EFFECTIVENESS ANALYSIS

There are three main factors that are quantified to accurately calculate the absolute cost-effectiveness: Repair/Replace Labor Costs, Replacement Cost, and Inspection Cost.

A. Repair/Replace Labor Cost for LDAR Rules

The labor cost associated with the repair/replacement of leaking components is one factor taken into consideration. The District worked with stakeholders, CARB, and independent LDAR companies to obtain and determine the labor cost to repair/replace a leaking piece of equipment. Using the information provided, the District calculated the average cost of labor rates, and the average time to repair a leaking piece of equipment. Table C-4 below identifies the fixed cost used in the calculation of repairing/replacing equipment.

B. Replacement Cost for LDAR Rules

The District calculated the replacement cost of leaking equipment. The cost associated with replacement can be found in Table C-4. The District worked with information provided by stakeholders and independent LDAR companies to obtain and determine the cost of replacing a piece of equipment. Additionally, understanding a component's potential to leak, and the probability of when the component can no longer function, is also critical to calculating the cost-effectiveness.

Table C-4 Constant in Quantifying Repairing and Replacing Components

Component Type	Leak Fraction at 500 ppmv[1]	Component Replacement Cost ($)[2]	Percentage Needing Repair at 500 ppmv[3]	Percentage of Leaking Components Needing Replacing at 500 ppmv[4]	Repair Labor Cost[5]	Average Repair times (hr)[6]	Average replace time (hr)[7]
Valves	0.0075	$150.00	70%	30%	$133/hr	0.17	4
Flanges	0.0075	$83.00	70%	30%	$133/hr	0.17	4
Connectors	0.0075	$55.40	70%	30%	$133/hr	0.17	4
Pumps*	0.0075	$166.10	-	30%	$133/hr	0	40
Open-ended Lines	0.0075	$20.00	70%	30%	$133/hr	0.17	4
Other Components*	0.0075	$221.40	-	30%	$133/hr	0	40

*Pumps and Other Components are determined by the District as components that cannot be easily repaired. All Pumps and Other Components found leaking when the leak fraction is applied to the total number of components are deemed as needing replacing.

[1] Leak Fraction = Estimated percentage of leaking components based on Rule 4409 section 5.1.4.4, district inspection experience, and discussions with industry vendors.
[2] Component Replacement Cost = average cost per component (Source: CARB, Industry Vendors)
[3] Percentage of Leaking Equipment Needing Replacing = Consistent with Subpart OOOOa at 500 ppmv (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[4] Percentage of Leaking Equipment Needing Replacing = Consistent with Subpart OOOOa at 500 ppmv
[5] Labor Cost = Average cost per hour (Source : CARB, Industry Vendors)
[6] Average Repair Time (hr) = Consistent with Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[7] Average Replacement Time (hr) = Based on average of 3 independent vendors

Tables C-5 through C-12 calculate the cost of repairing and replacing leaking components under the proposed 500 ppmv leak threshold.

The table below represents costs for components currently subject to the current leak threshold in Rule 4401 of 2,000 ppmv to comply with the proposed leak threshold of 500 ppmv.

Table C-5 Repair and Replacement Cost Analysis for Rule 4401 at 500 ppmv from 2,000 ppmv

Component Type	Number Components[8]	Leaking Components at 500 ppm[9]	Average Replacement Time (hr/leak) [10]	Average Repair Time (hr/leak)[11]	Repair and Replacement Time at 500 ppmv (hrs/yr)[12]	Annual Repair and Replacement Labor Cost[13]	Annual Replacement Part Cost at 500 ppm[14]	Total Annual Repair and Replacement Cost at 500 ppmv[15]
Valves	15,809	79.05	4.00	0.17	111.83	$14,762	$3,853	$18,615
Flanges	11,511	57.55	4.00	0.17	81.42	$10,748	$1,553	$12,301
Connectors	59,720	298.60	4.00	0.17	422.45	$55,763	$5,376	$61,139
Pumps	92	0.46	40.00	0.00	18.44	$2,434	$77	$2,511
Open-ended Lines	29	0.14	4.00	0.17	0.20	$27	$1	$28
Other Components	2,178	10.89	40.00	0.00	435.62	$57,502	$2,411	$59,913
Total	**89,339**	**446.70**			**1,069.96**	**$141,235**	**$13,271**	**$154,506**

The proposed changes to Rule 4401 introduce 804,053 components to District requirements. These components, previously subject to CARB's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities[16] (COGR), would now be subject to District requirements under Rule 4401. The costs in Table C-6 are associated with these components being subject to the proposed 500 ppmv leak threshold, instead of the 1,000 ppmv leak threshold in COGR.

[8] Number of components affected
[9] Number of leaking components = (Number of components) x (Leak Fraction in Table C-4)
[10] Average Replacement time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[11] Average Repair time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[12] Repair and Replacement Time = Number of Leaking Components x (Average Repair Time and Average Replacement Time)
[13] Annual Repair and Replacement Labor Cost = (Repair and Replacement Time) x ($133/hour)
[14] Annual Replacement Parts Cost = (Number of leaking component x replacement %) x (Cost of Part)
[15] Total Annual Repair and Replacement Cost = Annual Repair and Replacement Labor Cost + Annual Replacement Parts Cost
[16] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, October 2018, https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf

Table C-6 Repair and Replacement Cost Analysis for Rule 4401 at 500 ppmv from 1,000 ppmv

Component Type	Number Components [17]	Leaking Components at 500 ppmv[18]	Average Replacement Time (hr/leak)[19]	Average Repair Time (hr/leak)[20]	Repair and Replacement Time at 500 ppmv (hrs/yr)[21]	Annual Repair and Replacement Labor Cost[22]	Annual Replacement Part Cost at 500 ppmv[23]	Total Annual Repair and Replacement Cost at 500 ppmv[24]
Valves	142,282	355.70	4.00	0.17	605.41	605.41	$21,342	$101,256
Flanges	103,597	258.99	4.00	0.17	440.81	440.81	$8,599	$66,785
Connectors	537,484	1,343.71	4.00	0.17	2,286.99	2,286.99	$29,777	$331,660
Pumps	830	2.07	40.00	0.00	82.98	82.98	$345	$11,298
Open-ended Lines	257	0.64	4.00	0.17	1.10	1.10	$5	$150
Other Components	19,603	49.01	40.00	0.00	1,960.29	1,960.29	$10,850	$269,608
Total	**804,053**	**2,010.13**			**5,377.57**	**5,377.57**	**$70,917**	**$780,757**

Table C-7 Repair and Replacement Cost Analysis for Rule 4409 at 500 ppmv from 2000 ppmv (gas) and 1,000 ppmv (liquid)

Component Type	Number Components [17]	Leaking Components at 500 ppmv[18]	Average Replacement Time (hr/leak)[19]	Average Repair Time (hr/leak)[20]	Repair and Replacement Time at 500 ppmv (hrs/yr)[21]	Annual Repair and Replacement Labor Cost[22]	Annual Replacement Part Cost at 500 ppmv[23]	Total Annual Repair and Replacement Cost at 500 ppmv[24]
Valves	272,953	1,365	4.00	0.17	1,861.20	$254,866	$66,532	$321,398
Flanges	286,622	1,433	4.00	0.17	1,954.40	$267,629	$38,658	$306,287
Connectors	906,223	4,531	4.00	0.17	6,179.31	$846,172	$81,583	$927,755
Pumps	3,577	18	40.00	0.00	715.40	$94,433	$2,971	$97,403
Open-ended Lines	-	0	4.00	0.17	0	$-	$0	$-
Other Components	41,660	208	40.00	0.00	8,332.00	$1,099,824	$46,118	$1,145,942
Total	**1,511,035**	**7,555**			**19,042.31**	**$2,562,924**	**$235,861**	**$2,798,785**

[17] Number of components affected
[18] Number of leaking components = (Number of components) x (Leak Fraction in Table C-4)
[19] Average Replacement time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[20] Average Repair time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[21] Repair and Replacement Time = Number of Leaking Components x (Average Repair Time and Average Replacement Time)
[22] Annual Repair and Replacement Labor Cost = (Repair and Replacement Time) x ($133/hour)
[23] Annual Replacement Parts Cost = (Number of leaking component x replacement %) x (Cost of Part)
[24] Total Annual Repair and Replacement Cost = Annual Repair and Replacement Labor Cost + Annual Replacement Parts Cost

Table C-8 Repair and Replacement Cost Analysis for Rule 4455 at 500 ppmv

Component Type	Number Components [25]	Leaking Components at 500 ppmv[26]	Average Replacement Time (hr/leak)[27]	Average Repair Time (hr/leak)[28]	Repair and Replacement Time at 500 ppmv (hrs/yr)[29]	Annual Repair and Replacement Labor Cost[30]	Annual Replacement Part Cost at 500 ppmv[31]	Total Annual Repair and Replacement Cost at 500 ppmv[32]
Valves	-	-	4.00	0.17	-	-	-	-
Flanges	-	-	4.00	0.17	-	-	-	-
Connectors	-	-	4.00	0.17	-	-	-	-
Pumps	-	-	40.00	0.00	-	-	-	-
Open-ended Lines	-	-	4.00	0.17	-	-	-	-
Other Components	1,708	9	40.00	0.00	171	$22,546	$945	$491
Total	**1,708**	**9**			**171**	**$22,546**	**$945**	**$23,491**

The table below represents costs for components currently subject to the current leak threshold in Rule 4623 of 10,000 ppmv to comply with the proposed leak threshold of 500 ppmv.

Table C-9 Repair and Replacement Cost Analysis for Rule 4623 at 500 ppmv from 10,000 ppmv

Component Type	Number Components [25]	Leaking Components at 500 ppmv[26]	Average Replacement Time (hr/leak)[27]	Average Repair Time (hr/leak)[28]	Repair and Replacement Time at 500 ppmv (hrs/yr)[29]	Annual Repair and Replacement Labor Cost[30]	Annual Replacement Part Cost at 500 ppmv[31]	Total Annual Repair and Replacement Cost at 500 ppmv[32]
Valves	12,369	80.40	4.00	0.17	9.07	$1,197	$3,803.41	$5,000
Flanges	14,057	91.37	4.00	0.17	125.90	$16,619	$2,391.76	$19,011
Connectors	41,274	268.28	4.00	0.17	369.67	$48,797	$4,687.49	$53,484
Pumps	67	0.44	40.00	0.00	10.92	$1,441	$45.35	$1,487
Open-ended Lines	1	0.01	4.00	0.17	0.00	$-	$-	$-
Other Components	3,853	25.04	40.00	0.00	1,001.73	$132,228	$5,544.56	$137,773
Total	**71,621**	**465.54**			**1,517.29**	**$200,282**	**$16,472.57**	**$216,754**

[25] Number of components affected
[26] Number of leaking components = (Number of components) x (Leak Fraction in Table C-4)
[27] Average Replacement time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[28] Average Repair time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[29] Repair and Replacement Time = Number of Leaking Components x (Average Repair Time and Average Replacement Time)
[30] Annual Repair and Replacement Labor Cost = (Repair and Replacement Time) x ($133/hour)
[31] Annual Replacement Parts Cost = (Number of leaking component x replacement %) x (Cost of Part)
[32] Total Annual Repair and Replacement Cost = Annual Repair and Replacement Labor Cost + Annual Replacement Parts Cost

The proposed changes to Rule 4623 introduce 107,431 components to District requirements. These components, previously subject to COGR, would now be subject to District requirements under Rule 4623. The costs in Table C-10 are associated with these components being subject to the proposed 500 ppmv leak threshold, instead of the 1,000 ppmv leak threshold in COGR.

Table C-10 Repair and Replacement Cost Analysis for Rule 4623 at 500 ppmv from 1,000 ppmv

Component Type	Number Component	Leaking Components at 500 ppmv	Average Replacement Time (hr/leak)	Average Repair Time (hr/leak)	Repair and Replacement Time at 500 ppmv (hrs/yr)	Annual Repair and Replacement Labor Cost	Annual Replacement Part Cost at 500 ppmv	Total Annual Repair and Replacement Cost at 500 ppmv
Valves	18,553	46.38	4.00	0.17	78.94	$10,421	$2,782.98	$13,204
Flanges	21,085	52.71	4.00	0.17	89.72	$11,843	$1,750.07	$13,593
Connectors	61,911	154.78	4.00	0.17	263.43	$34,773	$3,429.87	$38,203
Pumps	101	0.25	40.00	0.00	10.08	$1,331	$41.86	$1,372
Open-ended Lines	2	0.00	4.00	0.17	0.01	$1	$0.04	$1
Other Components	5,779	14.45	40.00	0.00	577.92	$76,285	$3,198.79	$79,484
Total	**107,431**	**268.58**			**1,084.84**	**$134,653**	**$11,203.60**	**$145,857**

The modification of exemption 4.4 of Rule 4623 has introduced 811 tanks that were previously exempt. The District identified 210 of these tanks that will now be required to comply with Table 4 or Table 5 of proposed Rule 4623. Table C-11 illustrates the cost to retrofit these with a minimum form of control.

Table C-11 Addition of Pressure Vacuum Relief Valve for Tanks Subject to 4623

Component Type	Number of Tanks[33]	Annualized Cost of a PVRV [34]	Total
PVRV	210	$1,490	$312,900

[33] Number of tanks from exemption 4.4 (210) of Rule 4623 required to install a PVRV.
[34] Annualized cost over 10 years

Table C-12 Repair and Replacement Cost Analysis for Rule 4624 at 500 ppmv

Component Type	Number Components [35]	Leaking Components at 500 ppmv [36]	Average Replacement Time (hr/leak) [37]	Average Repair Time (hr/leak)[38]	Repair and Replacement Time at 500 ppmv (hrs/yr)[39]	Annual Repair and Replacement Labor Cost[40]	Annual Replacement Part Cost at 500 ppmv[41]	Total Annual Repair and Replacement Cost at 500 ppmv[42]
Valves	6,438	32.19	4.00	0.17	27.39	$3,616	$966	$4,582
Flanges	6,317	31.59	4.00	0.17	26.88	$3,548	$524	$4,072
Connectors	26,406	132.03	4.00	0.17	112.36	$14,831	$1,463	$16,294
Pumps	84	0.42	40.00	0.00	8.40	$1,109	$35	$1,144
Open-ended Lines	-	0.00	4.00	0.17	0.00	$-	$-	$-
Other Components	756	3.78	40.00	0.00	75.60	$9,979	$418	$10,398
Total	**40,001**	**200.01**			**250.63**	**$33,083**	**$3,406**	**$36,489**

C. Inspection Cost for LDAR Rules

The District concludes that under current rules, the majority of facilities are conducting quarterly LDAR inspections for current District requirements, COGR, or Best Management Practices. Table C-13 presents the total components affected by the proposed leak limit change. Table C-13 also uses labor information provided to the District.

[35] Number of components affected
[36] Number of leaking components = (Number of components) x (Leak Fraction in Table C-4)
[37] Average Replacement time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[38] Average Repair time is based on EPA rulemaking Subpart OOOOa (https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf)
[39] Repair and Replacement Time = Number of Leaking Components x (Average Repair Time and Average Replacement Time)
[40] Annual Repair and Replacement Labor Cost = (Repair and Replacement Time) x ($133/hour)
[41] Annual Replacement Parts Cost = (Number of leaking component x replacement %) x (Cost of Part)
[42] Total Annual Repair and Replacement Cost = Annual Repair and Replacement Labor Cost + Annual Replacement Parts Cost

Table C-13 Cost of LDAR Inspection at 500 ppmv

Rule	Total Components[43]	Component Check (hr)[44]	Inspection (hr)[45]	Labor Cost (hr)[46]	Increase Cost of Inspection at 500 ppmv (Quarter)[47]	Total Increased Annual Cost of LDAR Inspections[48]
4401	893,392	63	14,166	$133.00	$1,771,013	$2,879,631
4409	1,511,035	63	23,959	$133.00	$1,167,165	$4,633,556
4455	1,708	63	27	$133.00	$1,201	$4,767
4623	179,052	63	2,839	$133.00	$151,040	$824,472
4624	40,001	63	634	$133.00	$28,119	$111,631
Total	**2,625,188**	**-**	**41,626**	**-**	**$3,095,089**	**$8,454,056**

Table C-6 and Table C-10 identify components subject to COGR that will now be subject to District Rules 4401 and Rules 4623 respectively. Additionally, those same components are also used to calculate the cost of performing LDAR inspections at 500 ppmv. However, those components only saw a cost increase from lowering the leak threshold from 1,000 ppmv to 500 ppmv.

IV. INCREMENTAL COST-EFFECTIVENESS ANALYSIS

The CH&SC section 40920.6(a) requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option that would achieve the emission reduction objective of the proposed amendments. The incremental cost-effectiveness is the difference in cost between more effective controls divided by the additional emission reductions achieved. Incremental cost-effectiveness is calculated as follows:

$$\textit{Incremental Cost-Effectiveness} = (C_{alt} - C_{proposed}) / (E_{alt} - E_{proposed})$$

Where:
$C_{proposed}$ is the present worth value of the proposed control option;
$E_{proposed}$ are the emission reductions of the proposed control option;
C_{alt} is the present worth value of the alternative control option; and
E_{alt} are the emission reductions of the alternative control option

[43] Total components affected
[44] Component Check = (CARB information (34)+Company1 (100)+Company2 (150) / 3) x (1.5))*
[45] Inspected components per hour = (Total Components)/(Components Checked (hr))
[46] Labor Cost = (Company1 ($120) +Company2($120) + Company3($120) + Company4($170)) / 4
[47] Cost of Inspection Quarter= (Inspected components (hr)) x (Labor cost) – (Current Cost)
[48] Total Cost = (Cost of Inspection Quarter x 4) – (Current Cost)

A. 100 ppmv Leak Limit

The District evaluated the potential of lowering the LDAR threshold to 100 ppmv as shown in Table C-14 below. District staff estimates that a leak limit of 100 ppmv will likely result in more leaking components that need replacement when compared to a 500 ppmv limit.

Table C-14 Incremental Cost-Effectiveness at 100 ppmv

Incremental Cost-Effectiveness from 500 ppmv to 100 ppmv			
Rule	**Emission Reductions from 500 ppmv to 100 ppmv VOC tons/yr[49]**	**Cost Increase from 500 ppmv to 100 ppmv[50]**	**Incremental Cost-Effectiveness $/ton VOC[51]**
4401	7.88	$4,277,845	$543,004
4409	16.39	$7,327,239	$447,095
4455	0.05	$28,464	$630,797
4623	1.93	$754,804	$392,080
4624	0.43	$189,293	$435,826
Total	**26.67**	**$12,577,645**	**$471,581**

While the emission reductions of requiring a leak threshold of 100 ppmv are higher than the 500 ppmv threshold, the component replacement cost, along with the extra hours of labor needed to replace the faulty components, results in higher costs and decreased cost-effectiveness. The incremental cost-effectiveness analysis did not demonstrate that alternate leak levels were more cost effective, therefore this leak level was not chosen.

[49] Incremental Emissions Reduction= (Emissions Reduction at 100 ppmv) – (Emissions Reduction at 500 ppmv)
[50] Cost Increase = (Cost at 100 ppmv) – (Cost at 500 ppmv)
[51] Incremental Cost-effectiveness = (Cost Increase[58])/(Incremental Emissions Reduction[57])

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POTENTIAL AMENDMENTS TO RULES 4401, 4409, 4455, 4623, AND 4624— REQUIREMENTS FOR LEAK DETECTION AND REPAIR (LDAR) FROM OIL AND GAS PRODUCTION, STORAGE, AND TRANSFER OPERATIONS

SOCIOECONOMIC IMPACT ANALYSIS

Final

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1 EXECUTIVE SUMMARY

This report contains ERG's analysis of the socioeconomic impacts of potential amendments to the San Joaquin Valley Air Pollution Control District (SJVAPCD or District):

- Rule 4401: Steam-Enhanced Crude Oil Production Wells;
- Rule 4409: Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities;
- Rule 4455: Components at Petroleum Refineries, Gas Liquids Processing Facilities, And Chemical Plants;
- Rule 4623: Storage of Organic Liquids; and
- Rule 4624: Transfer of Organic Liquids

Potential amendments to Rules 4401, 4409, 4455, 4623, and 4624 would decrease volatile organic compound (VOC) emissions from oil and gas production facilities.

After providing an overview of demographic and economic trends in the District as a whole, ERG estimates the impacts of the potential amendments on entities that would incur costs under the potential amendments by comparing compliance costs to profits.

Table 1 through Table 5 summarize estimated compliance costs and projected impacts for each of the five rules. As shown in Table 1, Rule 4401 compliance costs incurred by companies are estimated to be low (approximately 2 percent of profits). These costs meet the threshold for economic feasibility (annual costs as a percentage of profits are less than 10 percent) used throughout the report. Compliance costs are only incurred by one sector, the crude petroleum and natural gas sector.

Table 1. Summary of Socioeconomic Impacts due to Potential Amendments to Rule 4401—Steam-Enhanced Crude Oil Production Wells

Sector	Total Companies	Total Annual Cost	Average Annual Cost per Company	Average Profits per Company	Cost as % Profits
Crude Petroleum and Natural Gas	27	$3,814,894	$141,292	$6,765,731	2.09%
Total/Average	**27**	**$3,814,894**	**$141,292**	**$6,765,731**	**2.09%**

Sources: ERG estimates based on SJVAPCD, 2023; IMPLAN, 2023; RMA, 2023; BEA, 2023; U.S. Census Bureau, 2020a.

As shown in Table 2, Rule 4409 compliance costs incurred are estimated to comprise a small percentage of profits across all affected sectors. Of note, profit data from the Risk Management Association (RMA) was unavailable for the Natural Gas Transmission sector. Despite assuming that firms with facilities in this sector generate no profit, the cost impacts of the rule still meet the definition of economic feasibility outlined above.

Table 2. Summary of Socioeconomic Impacts due to Potential Amendments to Rule 4409—Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

Sector	Total Companies [a]	Total Annual Cost	Average Annual Cost per Company	Average Profits per Company [b]	Cost as % Profits
Crude Petroleum and Natural Gas	29	$5,705,636	$196,746	$5,910,293	3.33%
Natural Gas Liquids	11	$1,651,631	$150,148	$4,510,487	3.33%
Natural Gas Transmission	1	$75,074	$75,074	$0	0.00%
Total/Average	**33**	**$7,432,341**	**$225,222**	**$6,697,390**	**3.36%**

Sources: ERG estimates based on SJVAPCD, 2023; IMPLAN, 2023; RMA, 2023; BEA, 2023; U.S. Census Bureau, 2020a.

[a] This represents the number of companies with facilities categorized within a given sector. Some companies have facilities categorized in different SIC code sectors. For this analysis, costs and profits for a company that has facilities across two or more SIC codes are split evenly across each SIC for that company's facilities.

[b] RMA does not have financial data available for the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

Table 3 presents the results for Rule 4455; compliance costs incurred by firms are estimated to be low (about one-one hundredth of a percent of profits) across all affected sectors.

Table 3. Summary of Socioeconomic Impacts due to Potential Amendments to Rule 4455—Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

Sector	Total Companies	Total Annual Cost	Average Annual Cost per Company	Average Profits per Company	Cost as % Profits
Natural Gas Liquids	2	$4,037	$2,018	$6,765,731	0.03%
Industrial Organic Chemicals, NEC - Aliphatics	6	$12,110	$2,018	$8,911,265	0.02%
Pesticides and Agricultural Chemicals, NEC	1	$2,018	$2,018	$991,252	0.20%
Petroleum Refining	4	$8,074	$2,018	$37,422,061	0.01%
Chemicals and Allied Products, NEC	1	$2,018	$2,018	$3,209,106	0.06%
Total/Average	**14**	**$28,257**	**$2,018**	**$15,777,689**	**0.01%**

Sources: ERG estimates based on SJVAPCD, 2023; IMPLAN, 2023; RMA, 2023; BEA, 2023; U.S. Census Bureau, 2020a.

Rule 4623 compliance costs incurred are estimated to comprise roughly 0.31 percent of profits across all affected sectors. These results are presented in Table 4. Similar to the Natural Gas Transmission sector in-scope of Rule 4409, profit data from RMA was unavailable for the Crude Petroleum Pipelines sector. Even when assuming that companies with facilities in either the Crude Petroleum Pipelines and Natural Gas Transmission sectors generate no profit, the cost impacts of the rule still meet the definition of economic feasibility.

Table 4. Summary of Socioeconomic Impacts due to Potential Amendments to Rule 4623—Storage of Organic Liquids

Sector	Total Companies [a]	Total Annualized Cost [b]	Average Annualized Cost per Company	Average Profits per Company [c]	Cost as % Profits
Crude Petroleum and Natural Gas	26	$716,591	$27,561	$6,245,290	0.44%
Natural Gas Liquids	5	$104,503	$20,901	$4,736,011	0.44%
Industrial Organic Chemicals, NEC - Aliphatics	2	$59,716	$29,858	$20,315,583	0.15%
Petroleum Refining	3	$89,574	$29,858	$37,422,061	0.08%
Products of Petroleum and Coal, Not Elsewhere Classified	1	$29,858	$29,858	$37,422,061	0.08%
Crude Petroleum Pipelines	2	$59,716	$29,858	$0	0.00%
Natural Gas Transmission	1	$14,929	$14,929	$0	0.00%
Petroleum Bulk Stations and Terminals	2	$59,716	$29,858	$4,514,480	0.66%
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	1	$29,858	$29,858	$4,514,480	0.66%
Farm Supplies - Lawn and Garden Supplies Sold Via Retail Method	2	$59,716	$29,858	$461,036	6.48%
Total/Average	**41**	**$1,224,177**	**$29,858**	**$9,532,744**	**0.31%**

Sources: ERG estimates based on SJVAPCD, 2023; IMPLAN, 2023; RMA, 2023; BEA, 2023; U.S. Census Bureau, 2020a.

[a] This represents the number of companies with facilities categorized within a given sector. Some companies have facilities categorized in different SIC code sectors. For this analysis, costs and profits for a company that has facilities across two or more SIC codes are split evenly across each SIC for that company's facilities.

[b] The total annualized cost is calculated by summing annualized one-time costs (annualized over a 10-year period using a 4 percent discount rate) and annual costs.

[c] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

Table 5 summarizes the results for Rule 4624. Compliance costs incurred by companies are projected to be approximately 0.05 percent of profits, even with some companies assumed to generate zero profit.

Table 5. Summary of Socioeconomic Impacts due to Potential Amendments to Rule 4624—Transfer of Organic Liquid

Sector	Total Companies [a]	Total Annual Cost	Average Annual Cost per Company	Average Profits per Company [b]	Cost as % Profits
Crude Petroleum and Natural Gas	7	$18,990	$2,713	$4,832,665	0.06%
Natural Gas Liquids	7	$18,990	$2,713	$4,832,665	0.06%
Industrial Organic Chemicals, NEC - Aliphatics	4	$15,192	$3,798	$11,762,345	0.03%
Nitrogenous Fertilizers	1	$3,798	$3,798	$991,252	0.38%
Petroleum Refining	4	$13,293	$3,323	$32,744,303	0.01%
Products of Petroleum and Coal, Not Elsewhere Classified	1	$3,798	$3,798	$37,422,061	0.01%
Special Warehousing and Storage, Not Elsewhere Classified	1	$3,798	$3,798	$766,972	0.50%
Crude Petroleum Pipelines	6	$22,788	$3,798	$0	0.00%
Transportation Services, Not Elsewhere Classified	1	$3,798	$3,798	$104,762	3.63%
Natural Gas Transmission	2	$7,596	$3,798	$0	0.00%
Chemicals and Allied Products, NEC	1	$3,798	$3,798	$753,420	0.50%
Petroleum Bulk Stations and Terminals	7	$26,586	$3,798	$3,869,554	0.10%
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	2	$5,697	$2,848	$3,385,860	0.08%
Total/Average	**39**	**$148,120**	**$3,798**	**$8,194,384**	**0.05%**

Sources: ERG estimates based on SJVAPCD, 2023; IMPLAN, 2023; RMA, 2023; BEA, 2023; U.S. Census Bureau, 2020a.

[a] This represents the number of companies with facilities categorized within a given sector. Some companies have facilities categorized in different SIC code sectors. For this analysis, costs and profits for a company that has facilities across two or more SIC codes are split evenly across each SIC for that company's facilities.

[b] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

As a secondary measure of impacts, ERG also used the IMPLAN (2023) input-output model to assess how firms with costs under the potential amendments might react by reducing employment, as well as a "ripple effect" felt if affected firms reduce purchases from their suppliers, and their suppliers in turn reduce their own purchases. For each of the five rules, these impacts make up less than **0.01 percent** of District-wide revenue and employment.

2 INTRODUCTION AND BACKGROUND

This report provides economic data and analysis in support of the District's assessment of the socioeconomic feasibility of potential amendments to existing Rules 4401, 4409, 4455, 4623, and 4624 for steam-enhanced crude oil production wells; components at light crude oil production facilities, natural gas production facilities, and natural gas processing facilities; components at petroleum refineries, gas liquids processing facilities, and chemical plants; storage of organic liquids; and transfer of organic liquid. This work was performed by ERG under District Agreement No. 21-4-22.

Gas and oil producing facilities are primarily involved in crude petroleum extraction, natural gas extraction, and oil transportation industries. The potential amendments would revise existing District Rules 4401, 4409, 4455, 4623, and 4624, which limited VOC emissions from oil and natural gas production facilities. The potential amendments to Rules 4401, 4409, 4455, 4623, and 4624 would align gas and oil production facilities with the findings of the District's expedited review of Best Available Retrofit Control Technology as required by Assembly Bill 617.

This analysis was prepared to meet the requirements of California Health and Safety Code §40728.5, which requires an assessment of the socioeconomic impacts of the adoption, amendment, or repeal of air district rules. It begins by providing an overview of demographic and economic trends in the District, and then estimates the economic impacts on specific entities subject to the potential rule amendments (including small entities), and how those economic impacts might affect the surrounding communities, including at-risk populations.

3 REGIONAL DEMOGRAPHIC AND ECONOMIC TRENDS

In this section ERG considers larger demographic and economic trends in the District, which includes eight counties that are home to over 4 million people.[1] These counties have become more populous over the last decade, and the median income (adjusted for inflation) has also increased. Utilities, wholesale and retail trade, and transportation, along with agriculture and oil and gas extraction, are the predominant industries within the District both in terms of establishments and employment.

3.1 REGIONAL DEMOGRAPHIC TRENDS

This section presents the demographic shifts within the District's jurisdiction from 2012 to 2022. At the time of the writing of this report, data are not available at the county level beyond the year 2021 with the exception of population data.[2] The District has experienced a greater population growth rate than the state as a whole and greater income growth than the state. The poverty rate throughout the district, while decreasing over time, is also doing so at a slightly faster pace than California as a whole.

The San Joaquin Valley contains over 11 percent of the state of California's population. Table 6 shows how this population has changed over the last 10 years. Table 6 also shows the compound annual growth rate (CAGR) between 2013 and 2022. The CAGR is the constant rate at which the population would have changed annually to increase from the 2013 level to the 2022 level.

Overall, the region has seen annual average population growth marginally higher than the state of California. Kings County, the county with the smallest population of the counties in the District, saw little growth in its population from 2013 to 2022. San Joaquin County saw the most growth, increasing at 1.37 percent annually.

[1] While only part of Kern County falls into the District's boundaries, all of Kern County is included in the data presented in this section, as the data were only available at the county level.

[2] ERG used one-year estimates to compile this data for other socioeconomic impact reports. Since U.S. Census Bureau announced they would not publish one-year estimates for the 2020 American Community Survey, ERG opted to use five-year estimates for demographic data for this report.

Table 6. Population Trends by County

County	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	CAGR 2013-2022
Fresno	951,514	960,567	969,488	976,830	985,238	991,950	999,101	1,009,503	1,012,992	1,015,190	0.72%
Kern [a]	862,000	869,176	876,031	880,856	887,356	893,758	900,202	905,828	912,351	916,108	0.68%
Kings	150,337	149,495	150,085	149,382	149,665	151,382	152,940	152,790	152,679	152,981	0.19%
Madera	151,370	153,456	153,576	153,956	155,423	156,882	157,327	156,343	158,910	160,256	0.64%
Merced	262,026	264,419	266,353	267,628	271,096	274,151	277,680	281,814	284,458	290,014	1.13%
San Joaquin	702,046	711,579	722,271	732,809	743,296	752,491	762,148	780,558	788,140	793,229	1.37%
Stanislaus	523,451	528,015	533,211	539,255	544,717	548,126	550,660	553,217	552,851	551,275	0.58%
Tulare	452,460	455,138	457,161	459,235	462,308	464,589	466,195	473,891	476,946	477,544	0.60%
SJVAPCD [a]	**4,055,204**	**4,091,845**	**4,128,176**	**4,159,951**	**4,199,099**	**4,233,329**	**4,266,253**	**4,313,944**	**4,339,327**	**4,356,597**	**0.80%**
California	**38,260,787**	**38,596,972**	**38,918,045**	**39,167,117**	**39,358,497**	**39,461,588**	**39,512,223**	**39,501,653**	**39,142,991**	**39,029,342**	**0.22%**

Source: U.S. Census Bureau, 2020b; U.S. Census Bureau, 2023a.

[a] While the SJVAPCD only includes a portion of Kern county, the data shown here are for the whole of the county.

Table 7 shows the median income by county for 2012 through 2021 (U.S. Census Bureau, 2023b). Median income growth rates varied across counties from 2012 to 2021, though the counties in the District as a whole had a CAGR of 1.26 percent overall; this is slightly lower than the growth rate of median income for the state of California (1.58 percent). Kern and Kings counties saw the lowest rates of growth in region (0.40 percent and 0.98 percent, respectively).

Table 7. Median Income by County [a]

County	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	CAGR 2012-2021
Fresno	$58,194	$56,970	$55,479	$54,969	$55,302	$57,538	$59,105	$61,131	$63,855	$65,569	1.33%
Kern [b]	$60,720	$60,707	$59,619	$59,578	$59,904	$60,013	$60,510	$60,430	$61,330	$62,945	0.40%
Kings	$62,036	$60,183	$58,106	$56,485	$56,839	$58,733	$62,108	$65,525	$68,827	$67,699	0.98%
Madera	$60,987	$57,047	$55,834	$54,774	$55,036	$56,924	$60,977	$65,227	$69,238	$71,382	1.76%
Merced	$55,425	$53,254	$52,859	$51,601	$53,417	$54,713	$57,800	$60,795	$62,984	$62,984	1.43%
San Joaquin	$68,567	$66,743	$65,362	$64,740	$66,229	$68,262	$70,502	$72,983	$76,734	$80,213	1.76%
Stanislaus	$63,442	$61,638	$60,845	$60,914	$62,073	$64,067	$66,169	$68,760	$70,299	$73,157	1.60%
Tulare	$55,728	$53,400	$52,610	$51,077	$51,483	$52,981	$54,790	$56,281	$58,739	$61,415	1.09%
SJVAPCD [b, c]	**$61,001**	**$59,542**	**$58,391**	**$57,824**	**$58,581**	**$60,142**	**$61,961**	**$63,842**	**$66,234**	**$68,306**	**1.26%**
California	**$78,116**	**$76,389**	**$75,471**	**$75,123**	**$76,742**	**$79,309**	**$82,128**	**$85,220**	**$87,965**	**$89,988**	**1.58%**

Source: U.S. Census Bureau, 2023b.

[a] Inflated values to 2022 dollars using the BEA (2023) GDP deflator.

[b] While the SJVAPCD only includes a portion of Kern county, the data shown here are for the whole of the county.

[c] Median income for SJV is a weighted average by population.

ERG compiled data related to poverty from the U.S. Census Bureau (2023c). The poverty threshold used to determine poverty status varies by family size and composition, and uses pre-tax income (not including capital gains or noncash benefits (U.S. Census Bureau, 2023d).

Poverty rates by county for the last decade are shown in Table 8. The poverty rate decreased in every county in the District in that time frame. The poverty rate within the District is higher than the state average, while declining at effectively the same rate overall compared to the state of California's rate of -2.4 percent. Fresno and Tulare counties have consistently had among the highest poverty rates in the District while Stanislaus and San Joaquin counties have had the two lowest. Stanislaus and San Joaquin counties also saw some of the steepest declines in poverty rates in the region.

Many of the District's leading industries, including agriculture, transportation, and manufacturing, typically employ a higher percentage of low income and less educated employees, and have unstable or seasonal employment needs (Abood, 2014), likely leading to the higher rates of poverty seen in the District.

Table 8. Poverty Rate by County

County	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	CAGR 2012 – 2021
Fresno	24.8%	26.0%	27.4%	26.8%	26.9%	25.4%	24.1%	22.5%	20.8%	20.2%	-2.25%
Kern [a]	22.5%	22.9%	23.4%	23.5%	23.1%	22.6%	22.0%	21.0%	20.4%	19.4%	-1.63%
Kings	20.7%	21.0%	22.7%	22.6%	21.6%	20.9%	20.8%	18.2%	16.0%	16.4%	-2.55%
Madera	21.1%	22.8%	23.2%	23.5%	22.1%	22.1%	20.8%	19.9%	19.0%	19.6%	-0.82%
Merced	24.6%	25.4%	25.6%	26.1%	24.2%	23.3%	22.7%	21.2%	18.8%	19.5%	-2.55%
San Joaquin	17.5%	18.2%	19.4%	18.6%	17.8%	17.1%	15.9%	14.5%	13.7%	13.5%	-2.84%
Stanislaus	19.2%	20.3%	20.3%	20.3%	18.2%	17.2%	16.1%	15.1%	13.5%	13.6%	-3.76%
Tulare	24.8%	26.2%	27.4%	28.1%	28.3%	27.1%	25.5%	23.8%	21.8%	19.8%	-2.47%
SJVAPCD [a]	**22.0%**	**22.9%**	**23.8%**	**23.6%**	**23.0%**	**22.0%**	**21.0%**	**19.6%**	**18.2%**	**17.7%**	**-2.38%**
California	**15.3%**	**15.9%**	**16.4%**	**16.3%**	**15.8%**	**15.1%**	**14.3%**	**13.4%**	**12.6%**	**12.3%**	**-2.40%**

Source: U.S. Census Bureau, 2023c.

[a] While the SJVAPCD only includes a portion of Kern county, the data shown here are for the whole of the county.

Table 9 shows the population below the poverty line from 2012 to 2021. While there has been an overall decline in the number of people below the poverty line from 2012 to 2021, the number has fluctuated during this period. The number of people in poverty grew by nearly 70,000 between 2012 and 2016 but has declined by nearly 180,000 since 2016.

The CAGR of population below the poverty line varies across counties. Fresno County has the largest population below the poverty line as of 2021, which coincides with its large population and relatively higher poverty rate. Stanislaus County had the largest annual decline in population under the poverty line over the ten-year period and had one of the lowest poverty rates in the region in 2021.

Table 9. Population Below Poverty Line by County

County	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	CAGR 2012-2021
Fresno	226,967	239,584	255,019	252,187	254,872	243,040	232,067	218,254	202,296	198,793	-1.46%
Kern [a]	180,779	186,811	192,972	195,744	194,354	191,123	187,232	179,980	175,902	169,289	-0.73%
Kings	27,679	28,019	30,244	29,900	28,661	28,013	28,084	24,725	21,908	22,449	-2.30%
Madera	29,900	32,604	33,290	33,968	32,043	32,244	30,549	29,273	28,062	28,921	-0.37%
Merced	61,914	64,490	65,552	67,417	62,661	60,861	59,660	56,217	50,124	52,771	-1.76%
San Joaquin	117,938	123,115	132,986	129,390	124,587	121,296	114,294	105,461	100,689	101,951	-1.61%
Stanislaus	97,847	104,173	104,786	105,927	95,739	91,210	86,066	81,415	73,072	74,272	-3.02%
Tulare	108,096	115,313	122,044	125,775	127,130	122,724	115,786	108,512	99,610	91,866	-1.79%
SJVAPCD [a]	**851,120**	**894,109**	**936,893**	**940,308**	**920,047**	**890,511**	**853,738**	**803,837**	**751,663**	**740,312**	**-1.54%**
California	**5,590,100**	**5,885,417**	**6,115,244**	**6,135,142**	**6,004,257**	**5,773,408**	**5,487,141**	**5,149,742**	**4,853,434**	**4,741,175**	**-1.81%**

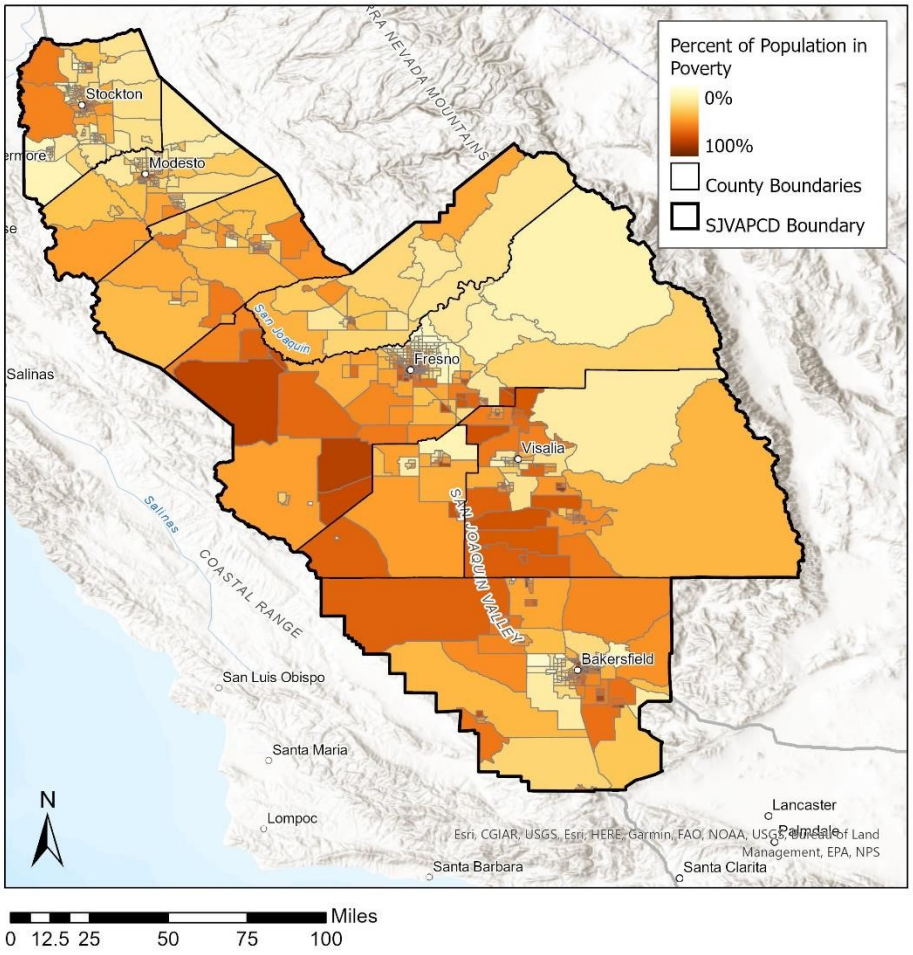
Source: U.S. Census Bureau, 2023c.

[a] While the SJVAPCD only includes a portion of Kern county, the data shown here are for the whole of the county.

Figure 1 shows where the population in poverty or at risk of poverty lives within the District[3] using CalEnviroScreen 4.0 (OEHHA, 2021a) data on the percent of population living below two times the federal poverty limit. CalEnviroScreen poverty data is derived from the US Census Bureau's American Community Survey 5-year estimates for 2015 to 2019. CalEnviroScreen uses a poverty threshold of two times the federal poverty level to account for the higher cost of living in California compared to other parts of the country (OEHHA, 2021b).

As shown in Table 9 above, roughly 20 percent of the District population is below the federal poverty limit, depending on the year. Using the higher CalEnviroScreen 4.0 threshold, nearly half (44.9 percent) of District residents are below twice the federal poverty limit (OEHHA, 2021a-b), reflected in the high poverty rates in the map in Figure 1 below.

Figure 1. Percentage of the Population Living Below Two Times the Federal Poverty Level by Census Tract (2015–2019)



Source: OEHHA, 2021a.
Map created by ERG using ArcGIS® software by Esri.

[3] Note that only the part of Kern County included in the SJVAPCD is shown. There are four census tracts on the eastern border of Kern County that are in the Eastern Kern Air Pollution Control District. The portions of these census tracts that fall outside of the SJVAPCD border are not shown.

3.2 REGIONAL ECONOMIC TRENDS

This section tracks the economic trends of the District from 2012 to 2021. At the time of the writing of this report, data are not available at the county level beyond the year 2021.[4] The total employment growth rate in the District is slightly higher that of California. Overall, employment, the number of establishments, and average pay have all increased across the District during that period.

Table 10 presents employment trends over the same 10-year span. During that period, overall employment throughout the District has also increased. The District as a whole saw a CAGR of 1.93 percent in employment over the last decade, slightly higher that of the entire state of California (1.63 percent). No individual county experienced a decline in employment, although Kern County has a notably lower growth rate (1.39 percent) than the other counties in the region.

All counties in the district experienced an employment growth rate greater than that of California as a whole, and San Joaquin County saw the largest employment growth rate (2.98 percent). This may be in part due to the California Central Valley Economic Development Corporation's (CCVEDC) efforts to encourage companies to locate within the District through tax credits and incentives and grants (CCVEDC, 2023). A few large employers (Amazon, Tesla, etc.) have moved to San Joaquin County in recent years, creating numerous job opportunities within the county. Some people have also moved from the more expensive Bay Area and Los Angeles-San Diego area to the Central Valley, with San Joaquin County being one of the more popular areas to relocate (Lillis, 2019).

[4] Due to lack of available one-year estimates for the 2020 American Community Survey, this economic trend analysis also looks at data through 2019.

Table 10. Employment Trends by County

County	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	CAGR 2012-2021
Fresno	439,605	455,451	465,023	475,905	486,870	496,698	508,801	520,083	506,047	522,348	1.93%
Kern [a]	381,650	393,903	404,213	404,831	406,705	411,621	422,760	429,837	418,395	431,960	1.39%
Kings	56,739	57,519	59,723	60,559	63,263	65,247	65,247	66,542	65,289	66,518	1.78%
Madera	59,606	61,063	62,799	61,468	63,717	64,549	66,067	67,100	66,529	68,862	1.62%
Merced	92,113	94,681	97,907	100,019	100,910	103,851	106,189	106,759	105,330	108,476	1.83%
San Joaquin	276,843	285,334	294,230	310,238	319,425	330,710	339,843	345,677	346,639	360,664	2.98%
Stanislaus	218,345	224,470	230,538	237,560	242,441	246,763	252,924	255,680	249,833	256,489	1.81%
Tulare	183,669	190,415	192,830	200,368	205,208	207,008	210,316	212,280	206,345	213,428	1.68%
SJVAPCD [a]	**1,708,570**	**1,762,836**	**1,807,263**	**1,850,948**	**1,888,539**	**1,926,447**	**1,972,147**	**2,003,958**	**1,964,407**	**2,028,745**	**1.93%**
California	**20,666,908**	**21,319,995**	**21,997,098**	**22,687,196**	**23,177,898**	**23,548,985**	**24,078,141**	**24,227,775**	**23,155,486**	**23,906,353**	**1.63%**

Source: BEA, 2023b.

[a] While the SJVAPCD only includes a portion of Kern county, the data shown here are for the whole of the county.

Table 11 shows the economic trends by industry in the District by presenting three snapshots from 2011 to 2021 using data from the Bureau of Labor Statistics' (BLS, 2022) Quarterly Census of Employment and Wages. The recent influx of new employers explains the continued growth in the utilities, trade and transportation industries. These industries have been the largest employers in the District for the last 11 years, followed closely by agriculture and oil and gas extraction. The education, health and social services industry has seen the greatest increase of establishments in the District over the past decade, although it is the one industry that has experienced a decrease in average pay over that same time frame. The information sector is the smallest industry in the district and has gotten smaller.

Table 11. Economic Trends in the San Joaquin Valley, 2011-2021 [a]

NAICS	Sector	2011			2016			2021		
		Establish-ments	Employ-ment	Average Annual Pay [c]	Establish-ments	Employ-ment	Average Annual Pay [c]	Establish-ments	Employ-ment	Average Annual Pay [c]
11, 21	Agriculture, Oil and Gas Extraction	7,452	201,824	$35,438	7,271	221,042	$39,231	7,197	205,981	$42,965
23	Construction	5,232	45,919	$61,249	5,599	60,004	$63,685	6,905	72,945	$70,245
31-33	Manufacturing	2,466	102,208	$60,439	2,555	108,755	$62,715	2,806	110,983	$66,949
22, 42, 44-45, 48-49	Utilities, Trade and Transportation	13,638	225,476	$46,463	14,773	264,822	$47,685	17,465	303,558	$53,933
51	Information	551	11,679	$73,825	480	10,395	$79,196	511	7,614	$86,468
52-53	Finance Activities	5,335	41,210	$59,595	5,754	41,888	$66,585	6,602	40,550	$74,777
54-56	Profession and Business Services	7,701	96,929	$52,386	8,332	110,250	$53,115	9,619	113,986	$60,306
61-62	Educational, Health and Social Services	7,555	146,642	$61,492	43,038	196,470	$55,093	57,592	224,463	$58,357
71-72	Leisure and Hospitality	5,827	96,872	$19,523	6,528	119,568	$21,234	7,660	124,203	$25,878
81	Other Services	41,302	49,975	$28,399	5,080	34,044	$39,416	5,725	35,011	$43,447
99	Unclassified	3,338	3,312	$48,350	3,218	4,463	$36,693	8	10	$66,224
SJV APCD Total/Average [b]		**100,397**	**1,022,046**	**$46,477**	**102,628**	**1,171,700**	**$48,032**	**122,090**	**1,239,304**	**$53,397**

Source: BLS, 2022.

[a] Includes all of Kern county.

[b] Annual average pay is a weighted average of the eight counties in the SJV APCD weighted by employment in sector.

[c] Annual average pay is adjusted to 2022 dollars using the BEA (2023) GDP deflator.

Table 12 presents the CAGR of the economic data from Table 11. The number of establishments, employment, and average annual pay have all increased over the last 11 years across the District. Health, education, and social services has seen the greatest growth in establishments and employment over that time frame, but it is the one industry that experienced a decrease in average pay (outside of the unclassified businesses). There are fewer establishments in the agriculture, oil, and gas extraction industry today than there were a decade ago, but employment and pay have both increased. The information industry has experienced the greatest decrease in employment across the District.

Table 12. Compound Annual Growth Rate of Establishments, Employment, and Annual Pay

NAICS	Sector	Establishments			Employment			Average Annual Pay		
		2011-2016	2016-2021	2011-2021	2011-2016	2016-2021	2011-2021	2011-2016	2016-2021	2011-2021
11, 21	Agriculture, Oil and Gas Extraction	-0.49%	-0.20%	-0.35%	1.84%	-1.40%	0.20%	2.05%	1.83%	1.94%
23	Construction	1.37%	4.28%	2.81%	5.50%	3.98%	4.74%	0.78%	1.98%	1.38%
31-33	Manufacturing	0.71%	1.89%	1.30%	1.25%	0.41%	0.83%	0.74%	1.32%	1.03%
22, 42, 44-45, 48-49	Utilities, Trade and Transportation	1.61%	3.40%	2.50%	3.27%	2.77%	3.02%	0.52%	2.49%	1.50%
51	Information	-2.72%	1.26%	-0.75%	-2.30%	-6.04%	-4.19%	1.41%	1.77%	1.59%
52-53	Finance Activities	1.52%	2.79%	2.15%	0.33%	-0.65%	-0.16%	2.24%	2.35%	2.30%
54-56	Profession and Business Services	1.59%	2.91%	2.25%	2.61%	0.67%	1.63%	0.28%	2.57%	1.42%
61-62	Educational, Health and Social Services	41.62%	6.00%	22.52%	6.02%	2.70%	4.35%	-2.17%	1.16%	-0.52%
71-72	Leisure and Hospitality	2.30%	3.25%	2.77%	4.30%	0.76%	2.52%	1.69%	4.04%	2.86%
81	Other Services	-34.24%	2.42%	-17.93%	-7.39%	0.56%	-3.50%	6.78%	1.97%	4.34%
99	Unclassified	-0.73%	-69.86%	-45.30%	6.15%	-70.48%	-44.03%	-5.37%	12.53%	3.20%
SJV APCD Total/Average		**0.44%**	**3.53%**	**1.98%**	**2.77%**	**1.13%**	**1.95%**	**0.66%**	**2.14%**	**1.40%**

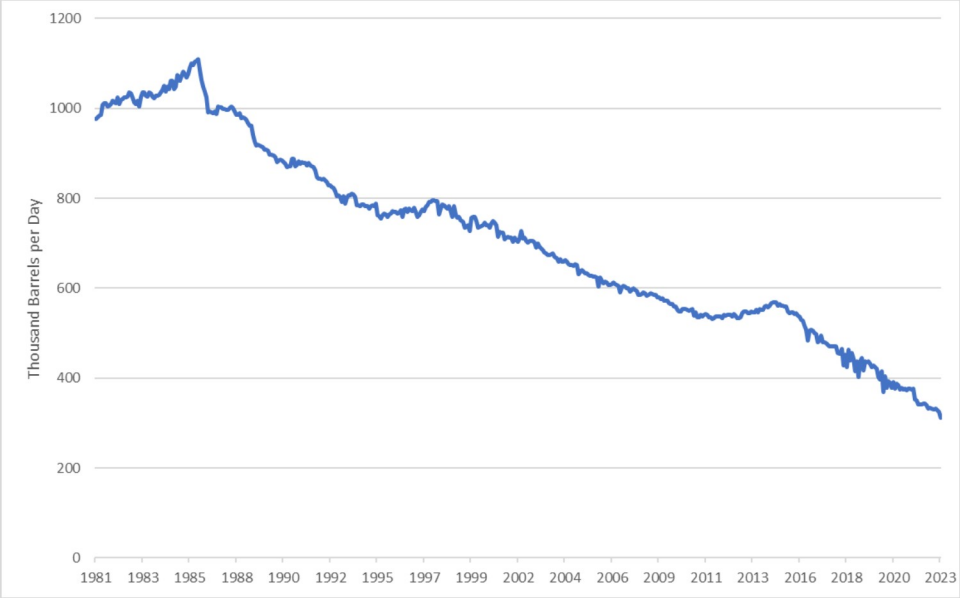
Source: BLS, 2022.

3.3 REGIONAL TRENDS IN OIL & GAS PRODUCTION FACILITIES

The five rules considered for amendment, Rules 4401, 4409, 4455, 4623, and 4624, cover firms across many sectors. These sectors are linked, however, in their connection to the production, transportation, and storage of oil and gas. Changes in the oil and gas production industries are likely to lead to changes in the supply of and demand for the production, transportation, and storage services offered by the majority of firms affected by rule amendments.

Oil production rates have increased nationally from 3.4 million barrels of crude oil produced in 2017 to 4.3 million barrels of crude oil produced in 2022, with Texas producing nearly half of all oil production in 2022 (EIA, 2023a). In 2022, California produced 122,400 thousand barrels of oil, significantly lower than their production in 2017, 173,400 thousand barrels of oil (EIA, 2023b). Oil production in California peaked in 1985 and has remained in a pattern of decline since (California Geologic Energy Management Division, 2020). Figure 2 shows the decline in California crude oil production from 1981 to 2021.

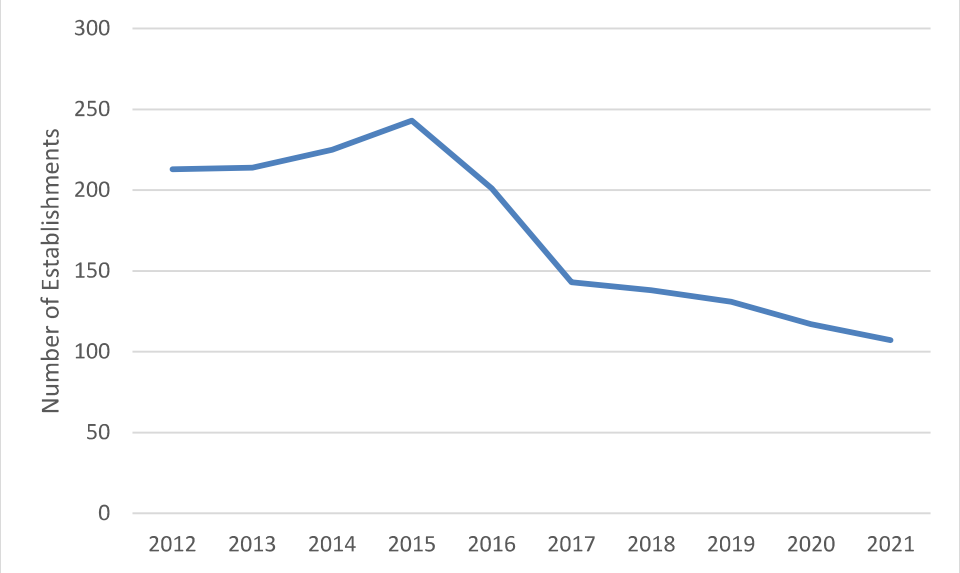
Figure 2. California Field Production of Crude Oil



Source: EIA, 2023b

In concurrence with the decline of crude oil production in California, the number of establishments classified as being primarily in the crude petroleum extraction industry has declined from 213 such establishments in 2012 to 117 establishments in 2020.[5] Figure 3 illustrates the decline in crude petroleum extraction establishments from 2012 to 2020.

Figure 3. Establishments in Crude Petroleum Extraction (NAICS 211120) in California

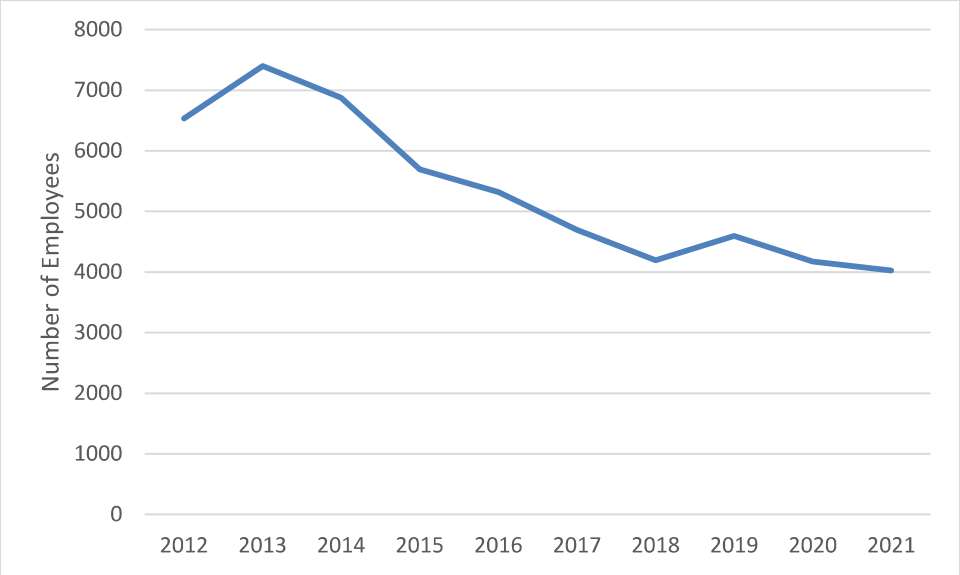


Source: U.S. Census Bureau, 2023e

In addition to declines in oil production and establishments, employment within the crude petroleum extraction industry has declined from 6,536 in 2012 to 4,173 in 2020. The decline in employment is depicted in Figure 4.

[5] In 2017, some changes were made to NAICS codes. These changes included restructuring of crude petroleum and natural gas extraction. The previous structure included crude petroleum and natural gas extraction under one NAICS code (211111), with natural gas liquid extraction separated into another NAICS code (211112). The 2017 restructuring split crude petroleum extraction (now NAICS 211120) from natural gas extraction (211130). NAICS 211130 also includes natural gas liquid extraction. This restructuring of NAICS codes may also play a role in why crude petroleum establishments and employment have decreased on the surface while natural gas activity has increased.

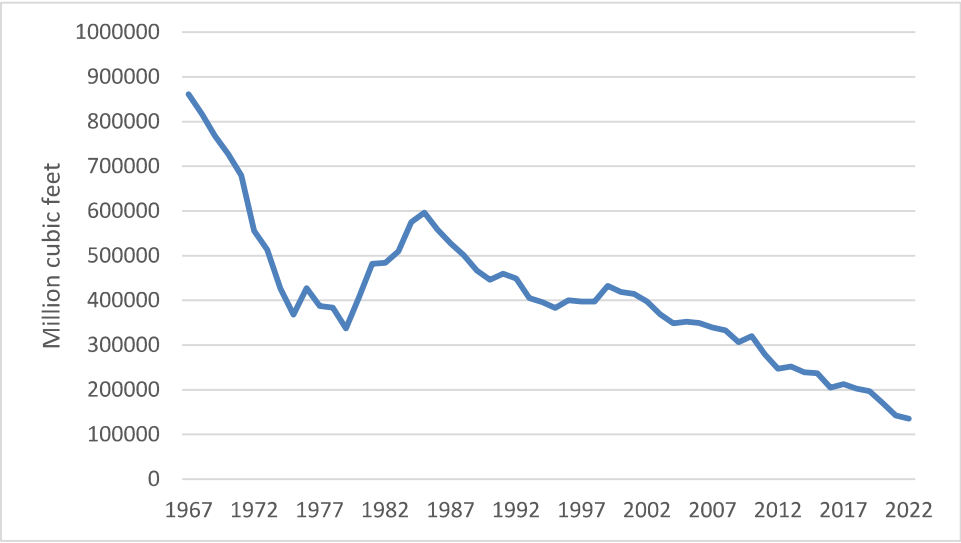
Figure 4. Employment in Crude Petroleum Extraction (NAICS 211120) in California



Source: U.S. Census Bureau, 2023e

U.S. natural gas production has increased nationally from 29.5 trillion cubic feet in 2012 to 43.3 trillion cubic feet in 2022 (EIA, 2023g). In 2012, California produced 246.8 billion cubic feet of natural gas. In 2022, California natural gas production decreased to 135.2 billion cubic feet (EIA, 2023c). Figure 5 depicts decreasing natural gas production in California from 1967 to 2022.

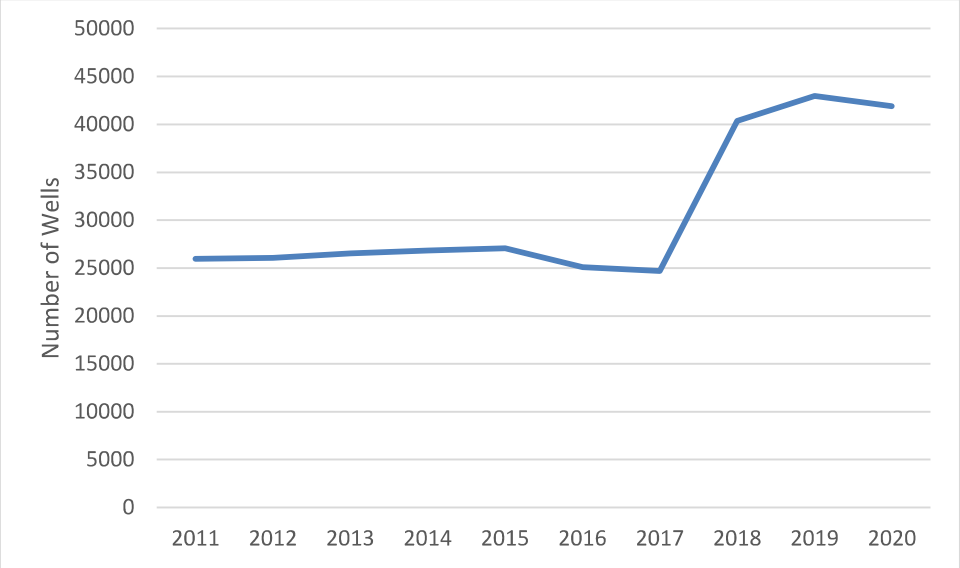
Figure 5. California Natural Gas Gross Withdrawals



Source: EIA, 2023c

Despite decreasing natural gas production rates, the number of natural gas wells has increased in California from 24,690 wells in 2017 to 41,923 wells in 2020. Figure 6 shows the increasing number of natural gas wells in California from 2011 to 2020. Between 2017 and 2018, EIA counts of the number of gas producing oil wells increase dramatically for many geographic areas; this could be due to changes in procedures related to data recording or reporting.

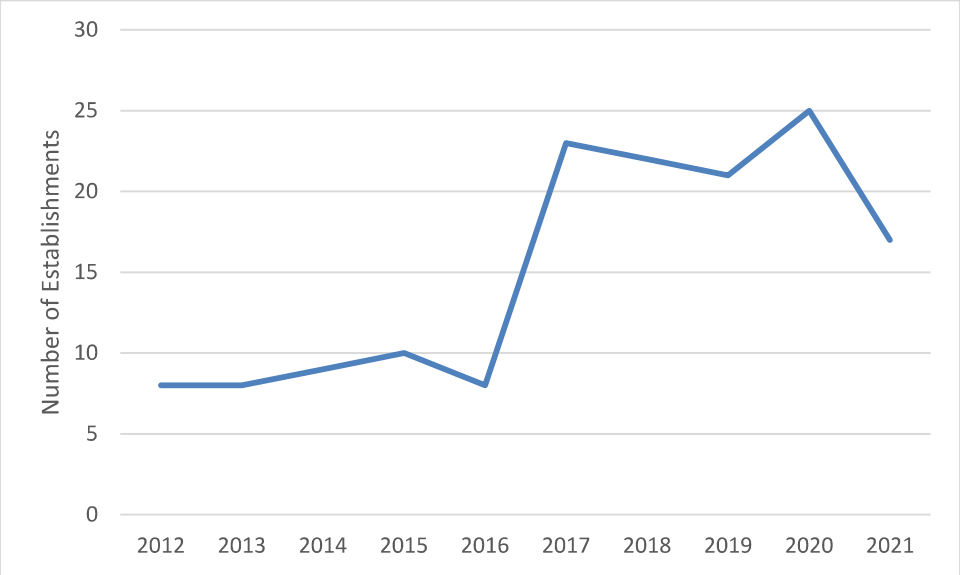
Figure 6. Number of Natural Gas Producing Wells in California



Source: EIA, 2023d

The number of establishments classified under the natural gas extraction industry in California has increased from eight establishments in 2012 to 25 establishments in 2020. Changes in the numbers of establishments primarily classified as being part of the natural gas extraction industry in California are depicted in Figure 7. Fluctuations in the number of natural gas extraction establishments in California seem to somewhat mirror patterns in the number of natural gas oil wells in California shown in Figure 6.

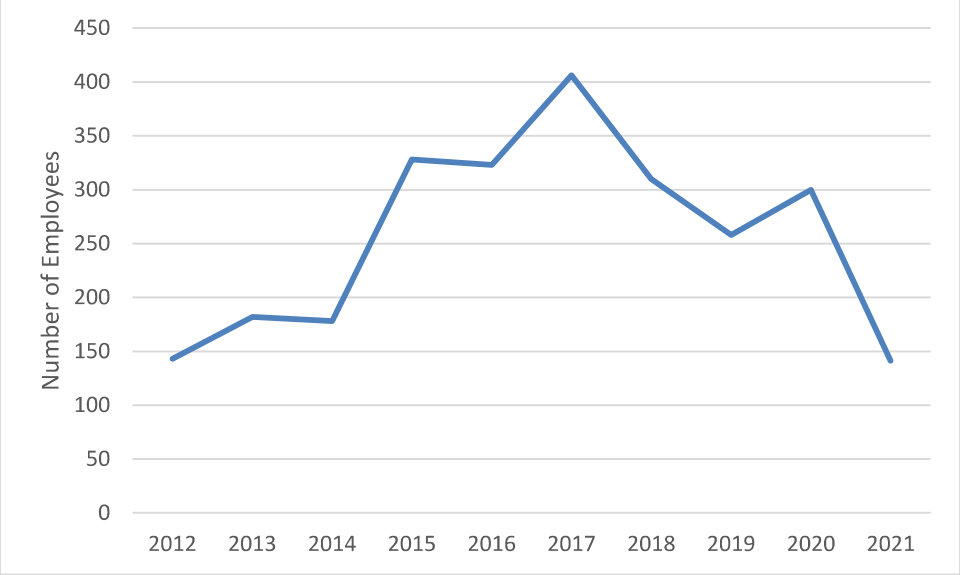
Figure 7. Establishments in Natural Gas Extraction (NAICS 211130) in California



Source: U.S. Census Bureau, 2023e

Employment in the natural gas extraction industry in California increased from 143 in 2012 to 406 in 2017 before falling back down to 258 in 2019. In 2020, employment began to increase again, reaching 300. Fluctuations in natural gas extraction employment in California are shown in Figure 8.

Figure 8. Employment in Natural Gas Extraction (NAICS 211130) in California



Source: U.S. Census Bureau, 2023e

4 SOCIOECONOMIC IMPACT ANALYSIS

ERG calculated the direct impacts of the proposed rule amendments by comparing the costs of compliance to profits of affected companies. ERG estimated potential employment impacts using IMPLAN's (2023) input-output model. Additionally, ERG used the IMPLAN model to capture indirect and induced impacts (i.e., impacts that might arise if directly impacted entities reduce purchases from their suppliers and households adjust their spending as a result of changes in earnings).

4.1 DATA SOURCES AND METHODOLOGY

To estimate socioeconomic impacts, ERG compares the costs of compliance with the potential amendments with profits per company. ERG sought to create a profile for each affected sector, including employment, revenue, profits, and average pay per employee. The process of estimating each of these endpoints also requires other data to be used (e.g., company name, address).

This section describes the data sources used to create the baseline industry profile and how socioeconomic impacts were estimated. The sections that follow detail the resulting profile of affected entities and the socioeconomic impacts of compliance with the potential rule amendments.

4.1.1 Baseline Industry Profile Estimates

SJVAPCD (2023) provided ERG with an initial list of affected facilities, including fields for facility ID, facility description, and Standard Industrial Classification (SIC) code. ERG converted the SIC codes to the North American Industry Classification System (NAICS) codes that are used with other sources of economic data used in the analysis using U.S. Census Bureau (2020c) concordances.[6] (See 5APPENDIX A for a list of the NAICS codes that mapped to each SIC code.)

ERG estimated company revenues and profits by dividing industry "sales, value of shipments, or revenues" by "number of firms" taken from the 2017 Economic Census for the relevant NAICS codes in the state of California results in estimated output per firm, where "firm" is assumed to be equivalent to the more generic term "company." This was inflated to represent 2022 dollars using the U.S. Bureau of Economic Analysis (BEA) gross domestic product implicit price deflator (BEA, 2023). Then, firm-level profits were estimated by multiplying estimated average firm revenues by the average profit rate for that NAICS code as derived from the Risk Management Association (RMA, 2023). The profit rate was calculated using net sales data for fiscal years 2016-2017 and 2022-2023 and a combined state and federal corporate tax rate for California of 28 percent (Watson, 2021) to calculate post-tax profits and then a post-tax profit rate. Fiscal year 2016-2017 was chosen because the profit rate calculated for NAICS 2111 (which is the predominant NAICS associated with companies in-scope of these rules) was the lowest of all years available. Fiscal year 2022-2023 represents the most recent data available. The average between these two percentages is used to represent the post-tax profit rate for each NAICS code. RMA does not have financial data available for two NAICS codes (4861, Pipeline Transportation of Crude Oil; and 4862, Pipeline Transportation of Natural Gas) that map to two of the SIC code sectors (SIC

[6] SIC codes were last updated in 1987, and NAICS codes were first issued in 1997. The U.S. Census Bureau's (2020d) concordances map 1987 SIC codes to 1997 NAICS codes, and from there to the NAICS codes that are revised every five years (thus far in 2002, 2007, 2012, and 2017). SIC and NAICS codes are available at different levels of granularity. The SIC codes used in SJVAPCD's (2023) data are 4-digit SIC codes, and ERG mapped these to 6-digit NAICS codes.

4612, Crude Petroleum Pipelines, and 4922, Natural Gas Transmissions, respectively) with companies in-scope of some of these rules. For these companies, ERG assumed zero percent profit to present extremely conservative estimates of impacts.

4.1.2 Estimating Impacts on Affected Entities

Cost estimates (i.e., the aggregated cost of the potential rule amendments to all impacted companies) were provided by SJVAPCD (2023). For Rule 4401, 4409, 4455, and 4624 costs reflect increased ongoing operation and maintenance (O&M) costs. Costs for Rule 4623 were calculated by summing the one-time capital costs (annualized over a 10-year period using a 4 percent discount rate) with annual O&M costs. To estimate impacts, the direct costs of the rule (i.e., the cost of compliance with the rule) are compared to profits for each SIC code. For companies with facilities categorized across two or more SIC codes, ERG evenly distributed the costs to a single company across the number of SIC codes that single company has listed within SJVAPCD's facility list. ERG also assumed even distribution of revenues and profits in these instances.

To estimate both direct employment impacts of the potential rule amendments and indirect and induced effects, ERG used IMPLAN's (2023) input-output model. IMPLAN "is a regional economic analysis software application that is designed to estimate the impact or ripple effect (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model" (IMPLAN, 2023).

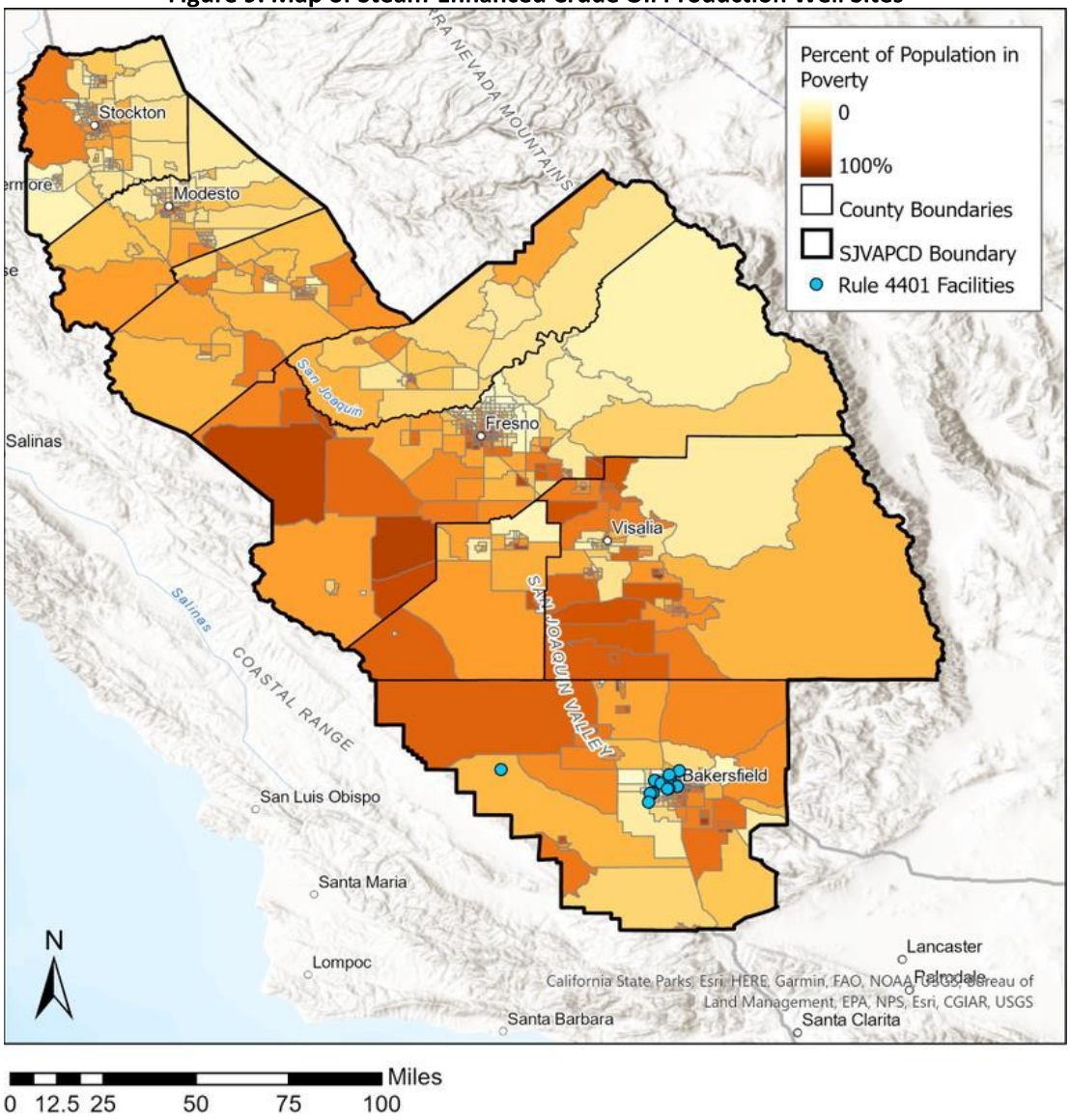
Based on the calculated costs, the IMPLAN model estimates how many jobs might be lost in reaction to the costs to affected companies. It also estimates indirect costs (i.e., the impact to affected firms' suppliers when the direct cost of rule compliance causes affected firms to reduce their purchases from those companies) and induced impacts (i.e., how households that have lost income in turn adjust their purchases).

4.2 RULE 4401 – STEAM-ENHANCED CRUDE OIL PRODUCTION WELLS

4.2.1 Profile of Affected Entities

Figure 9 presents the steam-enhanced crude oil production facilities affected by Rule 4401. Facilities were mapped using ArcGIS Pro 2.6.0 by number of sites occurring per Public Land Survey System (PLSS) Township and Range sector. Out of the 45 facilities provided, 22 had sufficient information to be mapped to a township and range, 14 of which had unique addresses. The majority of facilities are located within Kern County near Bakersfield, and a single facility along the western border of Kern County. There are no facilities in San Joaquin, Stanislaus, Merced, Madera, Kings or Tulare Counties.

Figure 9. Map of Steam-Enhanced Crude Oil Production Well Sites



Source data: SJVAPCD, 2023.
Map created by ERG using ArcGIS® software by Esri.

Table 13 includes a profile of firms affected by the potential amendments to Rule 4401 (i.e., those that will incur compliance costs). A total of 27 companies will incur costs.

Table 13. Profile of Entities Affected by Potential Amendments to Rule 4401—Steam-Enhanced Crude Oil Production Wells

Sector	Total Companies	Total, All Companies		
		Employees	Revenue	Profits
Crude Petroleum and Natural Gas	27	1,213	$2,265,311,582	$182,674,726
Total	**27**	**1,213**	**$2,265,311,582**	**$182,674,726**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; IMPLAN, 2023; BEA, 2023a.

Table 14 shows the characteristics of the average company affected by the potential amendments to Rule 4401. (The exact characteristics of individual firms could be either larger or smaller than these average estimates.)

Table 14. Characteristics of Entities with Costs due to the Potential Amendments to Rule 4401—Steam-Enhanced Crude Oil Production Wells

Sector	Average per Company			Average Annual Pay per Employee
	Employees	Revenue	Profits	
Crude Petroleum and Natural Gas	45	$83,900,429	$6,765,731	$134,134
Average	**45**	**$83,900,429**	**$6,765,731**	**$134,134**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; RMA, 2023; IMPLAN, 2023.

4.2.2 Compliance Cost Estimates

Compliance costs were estimated by SJVAPCD (2023), and include O&M costs for the units, beginning in 2024 and continuing indefinitely. Table 15 shows the O&M costs incurred by the Crude Petroleum and Natural Gas sector (the only sector affected by this rule). Annual costs would total around **$3,815,000** per year.

Table 15. Costs of Compliance with Potential Amendments to Rule 4401—Steam-Enhanced Crude Oil Production Wells

Sector	Annual O&M Costs [a]	Total Annual Costs
	2024	2024
Crude Petroleum and Natural Gas	$3,814,894	$3,814,894
Total	**$3,814,894**	**$3,814,894**

Source: SJVAPCD, 2023.

[a] Includes the increased costs to inspect, operate, and maintain equipment.

4.2.3 Impacts on Affected Entities

This section first discusses our primary impacts test, which compares compliance costs to profits for affected companies. ERG then discusses indirect and induced impacts to related industries.

4.2.3.1 Direct Impacts

The primary measure of economic feasibility used in this analysis is a comparison of total annual costs to affected facilities' profit and firms' profit where a threshold of 10 percent of profits indicates a significant adverse impact (Berck, 1995). ERG uses this measurement to inform the District's determination of economic feasibility of the rule amendments.

As shown in Table 16 overall rule costs comprise approximately **2.1 percent of company profits**.

Table 16. Economic Impacts for Entities Affected by Potential Amendments to Rule 4401—Steam-Enhanced Crude Oil Production Wells

Sector	Average Annual Cost per Company	Average Profits per Company	Cost as % Profits
Crude Petroleum and Natural Gas	$141,292	$6,765,731	2.09%
Average	**$141,292**	**$6,765,731**	**2.09%**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.

4.2.3.2 Employment, Indirect, and Induced Impacts

In addition to the primary test of direct impacts of costs on revenue, ERG also assessed potential direct impacts on employment, indirect impacts, and induced impacts using IMPLAN's (2023) input-output model. The IMPLAN model uses the direct costs of the rule to estimate "ripple effects" (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model (IMPLAN, 2023).

Outputs from the IMPLAN model include:

- **Direct employment impacts**, if facilities with compliance costs under the potential amendments were to attempt to offset these costs by reducing the number of employees.
- **Indirect revenue and employment impacts** that capture how directly affected firms might react to the direct cost of rule compliance by reducing purchases from their suppliers, and how those suppliers might in turn reduce employees.
- **Induced revenue and employment impacts** that capture how households will adjust their spending as a result of any changes in earnings.

Table 17 summarizes these impacts, which, taken together, may have a total impact on the District economy of less than **$3.8 million in revenue, with two jobs lost.**

Table 17. Direct, Indirect, and Induced Impacts of Potential Amendments to Rule 4401—Steam-Enhanced Crude Oil Production Wells

Sector	Direct		Indirect		Induced		Total	
	Revenue (Costs)	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Crude Petroleum and Natural Gas	$3,814,894	2	$6,594	0	$204	0	$3,821,692	2
Total	**$3,814,894**	**2**	**$6,594**	**0**	**$204**	**0**	**$3,821,692**	**2**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.
Note: Totals may not equal presented counts of revenue and employment for each sector due to rounding.

Table 18 compares these impacts to the total size of the District's economy (as estimated in the IMPLAN model). These impacts represent **just 0.001 percent** of revenue and employment District-wide.

Table 18. Comparison of Total Impacts against the District-Wide Economy for Potential Amendments to Rule 4401—Steam-Enhanced Crude Oil Production Wells

	Total Rule Impacts	Size of District Economy [a]	% of District Economy
Revenue	$3,821,692	$368,710,597,792	0.001%
Employment	2	1,982,068	0.000%

Source: ERG estimates based on IMPLAN, 2023.

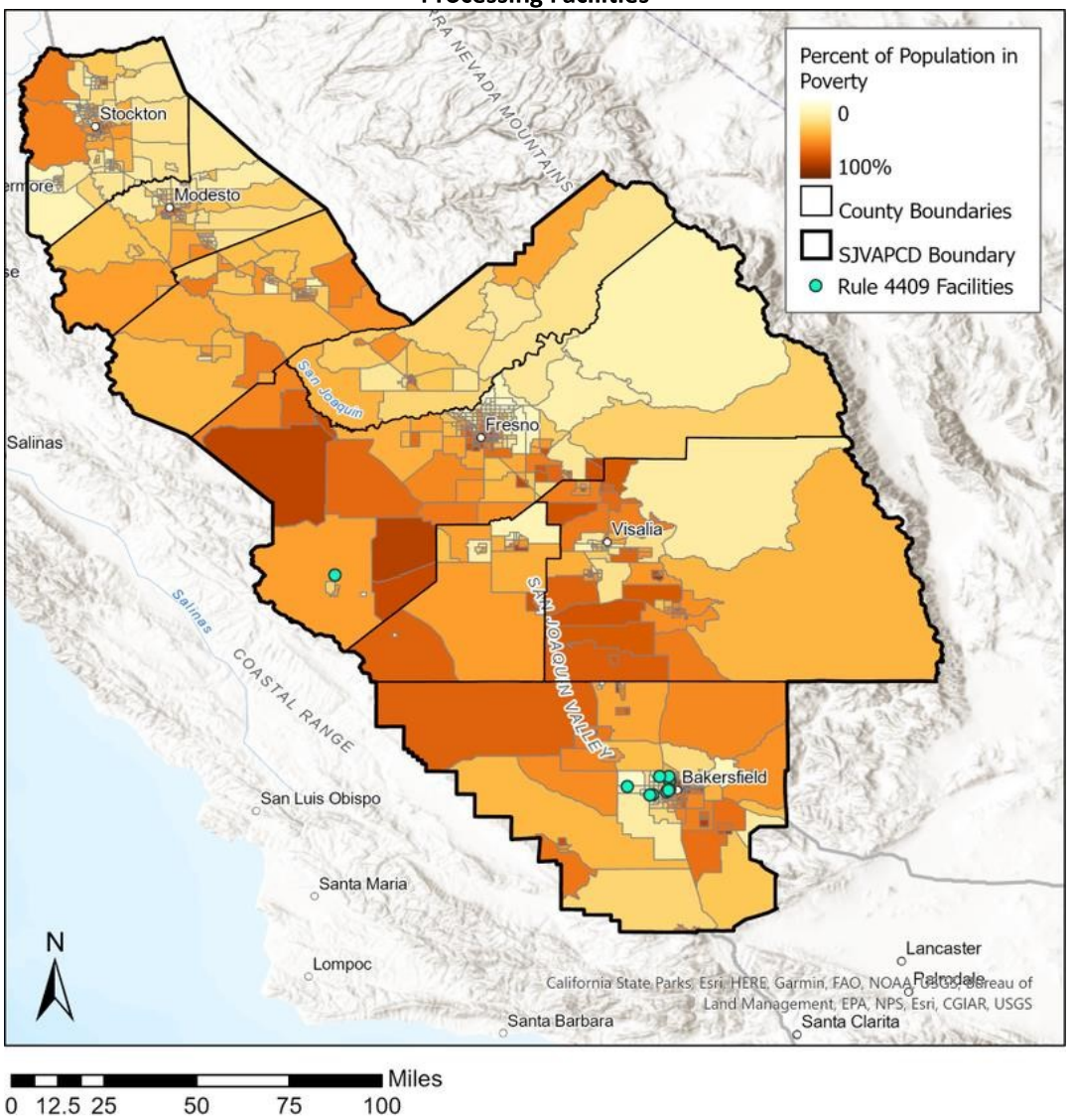
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

4.3 RULE 4409 – COMPONENTS AT LIGHT CRUDE OIL PRODUCTION FACILITIES, NATURAL GAS PRODUCTION FACILITIES, AND NATURAL GAS PROCESSING FACILITIES

4.3.1 Profile of Affected Entities

Figure 10 presents the Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities (whether affected by potential rule changes or not). Facilities were mapped using ArcGIS Pro 2.6.0 by number of sites occurring per Public Land Survey System (PLSS) Township and Range sector. Out of 59 facilities provided, 26 had sufficient information to be mapped, although there were only 10 unique addresses between the facilities. The majority of facilities are located outside of major metropolitan areas within Kern County.

Figure 10. Map of Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities



Source data: SJVAPCD, 2023.

Map created by ERG using ArcGIS® software by Esri.

Table 19 includes a profile of firms affected by the potential amendments to Rule 4409 (i.e., those that will incur compliance costs). A total of 33 companies will incur costs. Note that some companies have facilities across two or more sectors. For those companies, ERG evenly distributed the number employees, revenues, and profits between the relevant sectors.

Table 19. Profile of Entities Affected by Potential Amendments to Rule 4409—Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

Sector	Total Companies [a]	Total, All Companies		
		Employees	Revenue	Profits [b]
Crude Petroleum and Natural Gas	29	1,138	$2,125,477,534	$171,398,508
Natural Gas Liquids	11	329	$615,269,812	$49,615,358
Natural Gas Transmission	1	81	$85,566,822	$0
Total	**33**	**1,548**	**$2,826,314,168**	**$221,013,866**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; IMPLAN, 2023; BEA, 2023A.
[a] This represents the number of companies with facilities categorized within a given sector. Some companies have facilities categorized in different SIC code sectors. For this analysis, costs and profits for a company that has facilities across two or more SIC codes are split evenly across each SIC for that company's facilities.
[b] RMA does not have financial data available for the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

Table 20 shows the characteristics of the average company affected by the potential amendments to Rule 4409. (Individual companies might be either larger or smaller than these average estimates.)

Table 20. Characteristics of Entities with Costs due to the Potential Amendments to Rule 4409—Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

Sector	Average per Company			Average Annual Pay per Employee
	Employees	Revenue	Profits [a]	
Crude Petroleum and Natural Gas	39	$73,292,329	$5,910,293	$134,134
Natural Gas Liquids	30	$55,933,619	$4,510,487	$134,134
Natural Gas Transmission	81	$85,566,822	$0	$138,000
Average	**47**	**$85,645,884**	**$6,697,390**	**$134,336**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; RMA, 2023; IMPLAN, 2023.
[a] RMA does not have financial data available for the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

4.3.2 Compliance Cost Estimates

Compliance costs were estimated by SJVAPCD (2023), and include O&M costs beginning in 2024 and continuing indefinitely. Table 21 shows the annual costs incurred by sector in 2023 to be compliant with the rule by January 1, 2024. Annual costs would total about **$7,432,000** per year, with the majority of costs incurred by the "Crude Petroleum and Natural Gas" sector.

Table 21. Costs of Compliance with Potential Amendments to Rule 4409—Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

Sector	Annual O&M Costs [a]	Total Annual Costs
	2024	2024
Crude Petroleum and Natural Gas	$5,705,636	$5,705,636
Natural Gas Liquids	$1,651,631	$1,651,631
Natural Gas Transmission	$75,074	$75,074
Total	**$7,432,341**	**$7,432,341**

Source: SJVAPCD, 2023.

[a] Includes the increased costs to inspect, operate, and maintain equipment.

4.3.3 Impacts on Affected Entities

This section first discusses our primary impacts test, which compares compliance costs to profits for affected companies. ERG then discusses indirect and induced impacts to related industries.

4.3.3.1 Direct Impacts

The primary measure of determining economic feasibility is a comparison of total annual costs to profits for affected firms, with a threshold of 10 percent of profits indicating a finding of significant adverse impact (Berck, 1995). Therefore, ERG uses this comparison to aid in the District's determination of economic feasibility of the rule amendments.

As shown in Table 22, overall rule impacts are just over **3.3 percent of profits**. Neither sector for which ERG had sufficient profit data faces significant cost impacts as defined above. The Natural Gas Transmission sector would need to have a profit rate lower than 0.9 percent in order to have this rule be economically infeasible for that sector. Even if expenses for this sector were double its revenues, the rule would still be feasible overall.

Table 22. Economic Impacts for Entities Affected by Potential Amendments to Rule 4409—Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

Sector	Average Annual Cost per Company	Average Profits per Company [a]	Cost as % Profits
Crude Petroleum and Natural Gas	$196,746	$5,910,293	3.33%
Natural Gas Liquids	$150,148	$4,510,487	3.33%
Natural Gas Transmission	$75,074	$0	0.00%
Average	**$225,222**	**$6,697,390**	**3.36%**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.
[a] RMA does not have financial data available for the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

4.3.3.2 Employment, Indirect, and Induced Impacts

In addition to the primary test of direct impacts of costs on revenue, ERG also assessed potential direct impacts on employment, indirect impacts, and induced impacts using IMPLAN's (2023) input-output model. The IMPLAN model uses the direct costs of the rule to estimate "ripple effects" (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model (IMPLAN, 2023).

Outputs from the IMPLAN model include:

- **Direct employment impacts**, if facilities with compliance costs under the potential amendments were to attempt to offset these costs by reducing the number of employees.
- **Indirect revenue and employment impacts** that capture how directly affected firms might react to the direct cost of rule compliance by reducing purchases from their suppliers, and how those suppliers might in turn reduce employees.
- **Induced revenue and employment impacts** that capture how households will adjust their spending as a result of any changes in earnings.

Table 23 summarizes these impacts, which, taken together, are estimated to have a total impact on the District economy of approximately **$7,500,000 in revenue, with 5 jobs lost.**

Table 23. Direct, Indirect, and Induced Impacts of Potential Amendments to Rule 4409—Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

Sector	Direct		Indirect		Induced		Total	
	Revenue (Costs)	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Crude Petroleum and Natural Gas	$5,705,636	3	$13,165	0	$401	0	$5,719,202	3
Natural Gas Liquids	$1,651,631	1	$13,165	0	$401	0	$1,665,197	1
Natural Gas Transmission	$75,074	0	$14,354	0	$3,301	0	$92,728	0
Total	**$7,432,341**	**5**	**$40,684**	**0**	**$4,102**	**0**	**$7,477,128**	**5**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.
Note: Totals may not equal presented counts of revenue and employment for each sector due to rounding.

Table 24 compares these impacts to the total size of the District's economy (as estimated in the IMPLAN model). These impacts represent **less than 0.01 percent** of revenue and employment District-wide.

Table 24. Comparison of Total Impacts against the District-Wide Economy for Potential Amendments to Rule 4409—Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities

	Total Rule Impacts	Size of District Economy [a]	% of District Economy
Revenue	$7,477,128	$368,710,597,792	0.002%
Employment	5	1,982,068	0.000%

Source: ERG estimates based on IMPLAN, 2023.

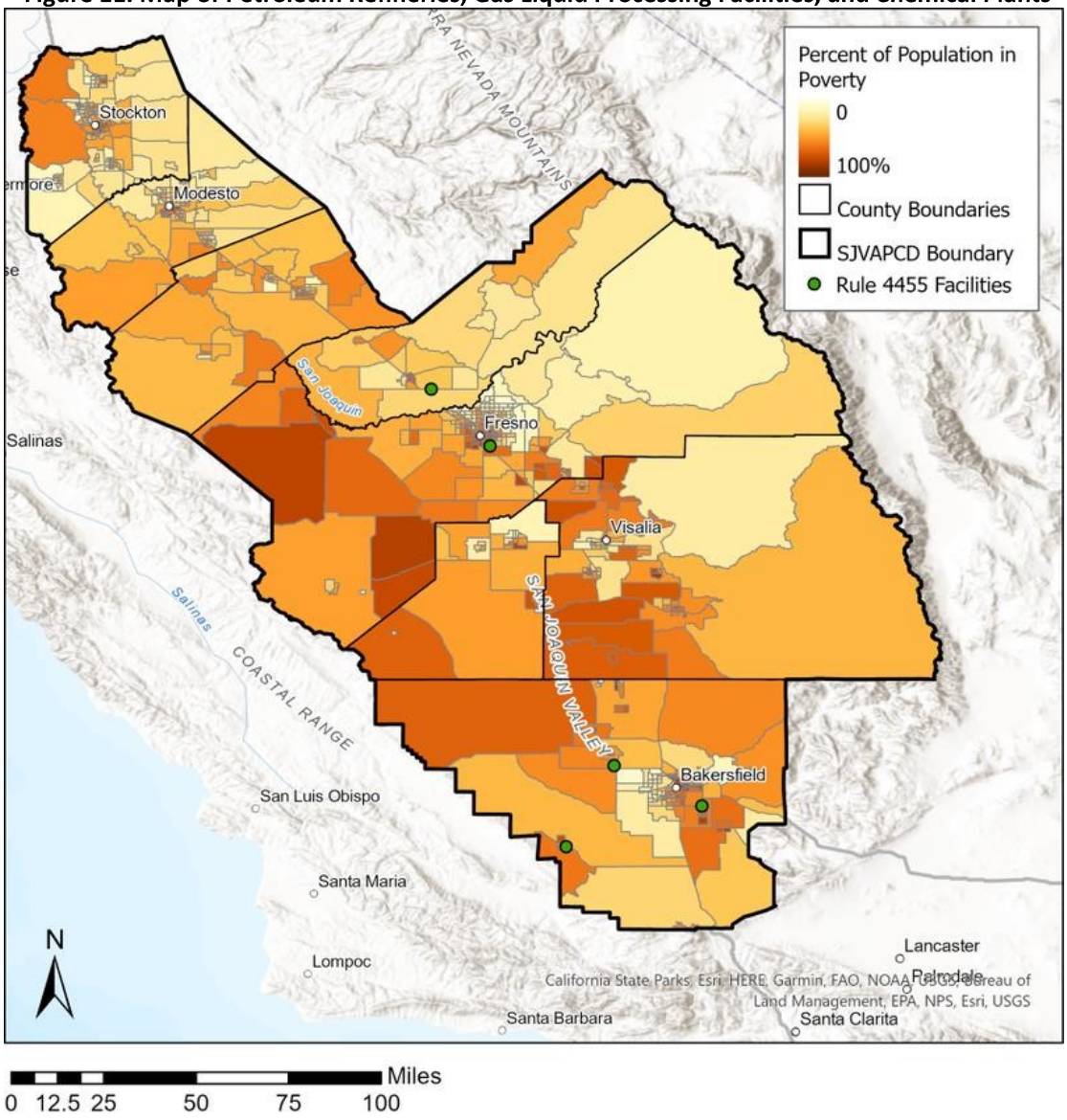
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

4.4 RULE 4455 – COMPONENTS AT PETROLEUM REFINERIES, GAS LIQUIDS PROCESSING FACILITIES, AND CHEMICAL PLANTS

4.4.1 Profile of Affected Entities

Figure 11 presents a map of affected Petroleum Refineries, Gas Liquid Processing Facilities, and Chemical Plants. Facilities were mapped using ArcGIS Pro 2.6.0. Out of the 16 facilities provided, five had sufficient information to be mapped. These facilities are located in Kern, Fresno, and Madera Counties.

Figure 11. Map of Petroleum Refineries, Gas Liquid Processing Facilities, and Chemical Plants



Source data: SJVAPCD, 2023.
Map created by ERG using ArcGIS® software by Esri.

Table 25 includes a profile of firms affected by the potential amendments to Rule 4455 (i.e., those that will incur compliance costs). A total of 14 companies will incur costs.

Table 25. Profile of Entities Affected by Potential Amendments to Rule 4455—Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

Sector	Total Companies	Total, All Companies		
		Employees	Revenue	Profits
Natural Gas Liquids	2	90	$167,800,858	$13,531,461
Industrial Organic Chemicals, NEC – Aliphatics	6	363	$1,001,634,433	$53,467,590
Pesticides and Agricultural Chemicals, NEC	1	24	$16,789,494	$991,252
Petroleum Refining	4	525	$2,970,004,812	$149,688,243
Chemicals and Allied Products, NEC	1	46	$51,826,646	$3,209,106
Total	**14**	**1,048**	**$4,208,056,243**	**$220,887,652**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; IMPLAN, 2023; BEA, 2023a.

Table 26 shows the characteristics of the average firm affected by the potential amendments to Rule 4455. (Individual firms may be either larger or smaller than these average estimates.)

Table 26. Characteristics of Entities with Costs due to the Potential Amendments to Rule 4455—Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

Sector	Average per Company			Average Annual Pay per Employee
	Employees	Revenue	Profits	
Natural Gas Liquids	45	$83,900,429	$6,765,731	$134,134
Industrial Organic Chemicals, NEC – Aliphatics	61	$166,939,072	$8,911,265	$118,045
Pesticides and Agricultural Chemicals, NEC	24	$16,789,494	$991,252	$78,977
Petroleum Refining	131	$742,501,203	$37,422,061	$136,442
Chemicals and Allied Products, NEC	46	$51,826,646	$3,209,106	$107,644
Average	**75**	**$300,575,446**	**$15,777,689**	**$127,280**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; RMA, 2023; IMPLAN, 2023.

4.4.2 Compliance Cost Estimates

Compliance costs were estimated by SJVAPCD (2023), and include O&M costs beginning in 2024 and continuing indefinitely. Table 27 shows the annual costs incurred by sector. Annual costs would total about **$28,000** per year over 10 years.

Table 27. Costs of Compliance with Potential Amendments to Rule 4455—Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

Sector	Annual O&M Costs [a]	Total Annual Cost
	2024	2024
Natural Gas Liquids	$4,037	$4,037
Industrial Organic Chemicals, NEC – Aliphatics	$12,110	$12,110
Pesticides and Agricultural Chemicals, NEC	$2,018	$2,018
Petroleum Refining	$8,074	$8,074
Chemicals and Allied Products, NEC	$2,018	$2,018
Total	**$28,257**	**$28,257**

Source: SJVAPCD, 2023.

[a] Includes the increased costs to inspect, operate, and maintain equipment.

4.4.3 Impacts on Affected Entities

This section first discusses our primary impacts test, which compares compliance costs to profits for affected companies. ERG then discusses indirect and induced impacts to related industries.

4.4.3.1 Direct Impacts

The primary measure of determining economic feasibility compares total annual costs to profits for affected firms, with a threshold of 10 percent of profits indicating a finding of significant adverse impact (Berck, 1995). Therefore, ERG uses this comparison to aid in the District's determination of economic feasibility of the rule amendments.

As shown in Table 28, overall rule impacts are around **0.01 percent of profits**. No sector faces significant cost impacts as defined above.

Table 28. Economic Impacts for Entities Affected by Potential Amendments to Rule 4455—Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

Sector	Average Annual Cost per Company	Average Profits per Company	Cost as % Profits
Natural Gas Liquids	$2,018	$6,765,731	0.03%
Industrial Organic Chemicals, NEC – Aliphatics	$2,018	$8,911,265	0.02%
Pesticides and Agricultural Chemicals, NEC	$2,018	$991,252	0.20%
Petroleum Refining	$2,018	$37,422,061	0.01%
Chemicals and Allied Products, NEC	$2,018	$3,209,106	0.06%
Average	**$2,018**	**$15,777,689**	**0.01%**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.

4.4.3.2 Employment, Indirect, and Induced Impacts

In addition to the primary test of direct impacts of costs on revenue, ERG also assessed potential direct impacts on employment, indirect impacts, and induced impacts using IMPLAN's (2023) input-output model. The IMPLAN model uses the direct costs of the rule to estimate "ripple effects" (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model" (IMPLAN, 2023).

Outputs from the IMPLAN model include:

- **Direct employment impacts**, if facilities with compliance costs under the potential amendments were to attempt to offset these costs by reducing the number of employees.
- **Indirect revenue and employment impacts** that capture how directly affected firms might react to the direct cost of rule compliance by reducing purchases from their suppliers, and how those suppliers might in turn reduce employees.
- **Induced revenue and employment impacts** that capture how households will adjust their spending as a result of any changes in earnings.

Table 29 summarizes these impacts, which, taken together, may have a total impact on the District economy of **$29,000 in revenue, with no jobs lost.**

Table 29. Direct, Indirect, and Induced Impacts of Potential Amendments to Rule 4455—Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

Sector	Direct		Indirect		Induced		Total	
	Revenue (Costs)	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Natural Gas Liquids	$4,037	0	$371	0	$2	0	$4,409	0
Industrial Organic Chemicals, NEC – Aliphatics	$12,110	0	$11	0	$0	0	$12,121	0
Pesticides and Agricultural Chemicals, NEC	$2,018	0	$9	0	$0	0	$2,028	0
Petroleum Refining	$8,074	0	$202	0	$7	0	$8,282	0
Chemicals and Allied Products, NEC	$2,018	0	$2	0	$0	0	$2,021	0
Total	**$28,257**	**0**	**$595**	**0**	**$9**	**0**	**$28,862**	**0**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.

Note: Totals may not equal presented counts of revenue and employment for each sector due to rounding.

Table 30 compares these impacts to the total size of the District's economy (as estimated in the IMPLAN model). These impacts represent **less than 0.001 percent** of revenue and employment District-wide.

Table 30. Comparison of Total Impacts against the District-Wide Economy for Potential Amendments to Rule 4455—Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

	Total Rule Impacts	Size of District Economy [a]	% of District Economy
Revenue	$28,862	$368,710,597,792	0.000%
Employment	0	1,982,068	0.000%

Source: ERG estimates based on IMPLAN, 2023.

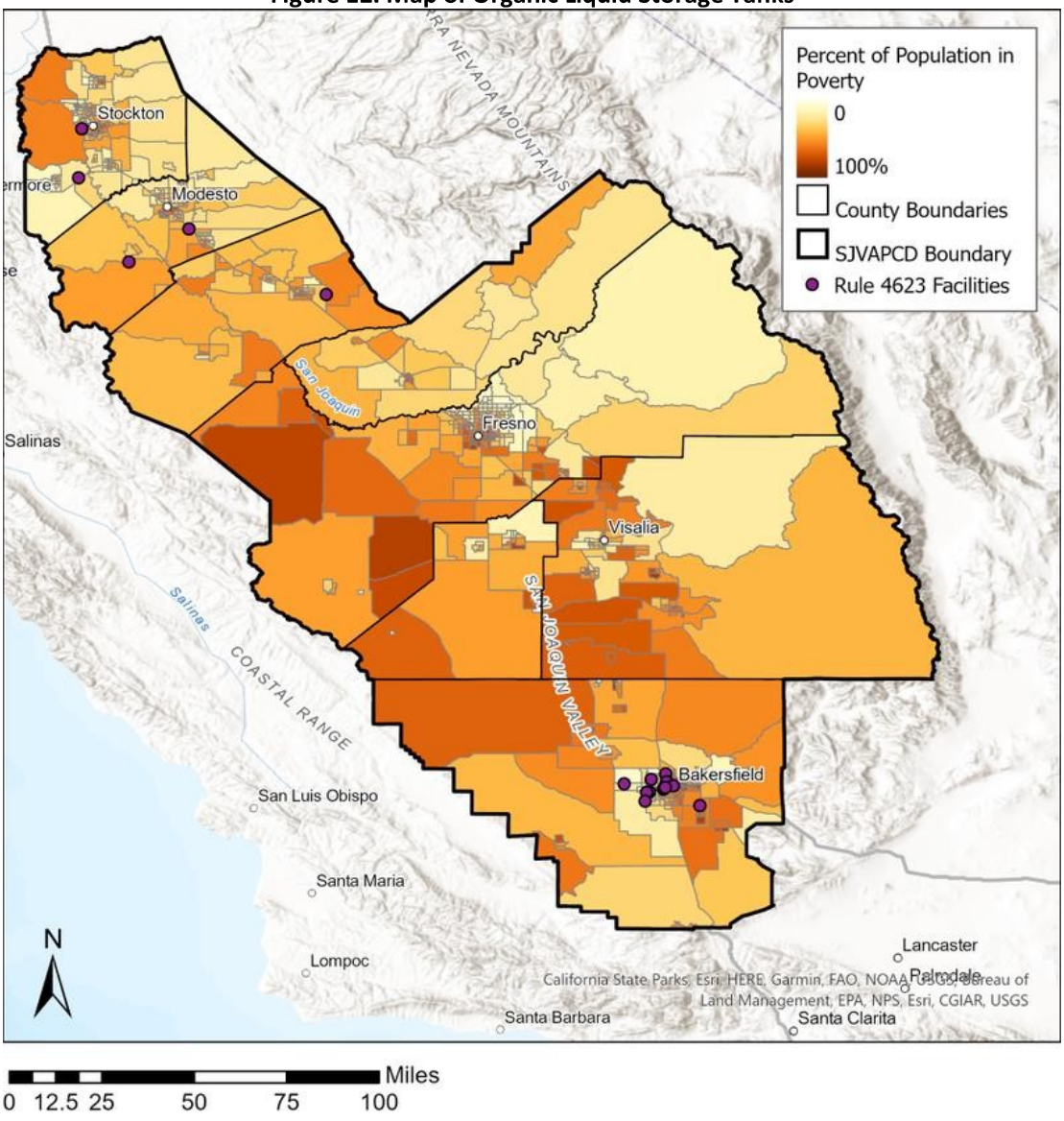
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

4.5 RULE 4623 – STORAGE OF ORGANIC LIQUIDS

4.5.1 Profile of Affected Entities

Figure 12 presents the in-scope facilities with organic liquid storage tanks. Facilities were mapped using ArcGIS Pro 2.6.0. There were 63 facilities provided, 29 of which provided sufficient information to be mapped. The majority of facilities are located in and around Bakersfield, while a handful of other facilities are located in the three northernmost counties, San Joaquin, Stanislaus, and Merced.

Figure 12. Map of Organic Liquid Storage Tanks



Source data: SJVAPCD, 2023.
Map created by ERG using ArcGIS® software by Esri.

Table 31 includes a profile of firms affected by the potential amendments to Rule 4623 (i.e., those that will incur compliance costs). A total of 41 firms will incur costs. Note that some companies have facilities across two or more sectors. For those companies, ERG evenly distributed the number employees, revenues, and profits between the relevant sectors.

Table 31. Profile of Entities Affected by Potential Amendments to Rule 4623—Storage of Organic Liquids

Sector	Total Companies [a]	Total, All Companies		
		Employees	Revenue	Profits [b]
Crude Petroleum and Natural Gas	26	1,078	$2,013,610,295	$162,377,534
Natural Gas Liquids	5	157	$293,651,501	$23,680,057
Industrial Organic Chemicals, NEC – Aliphatics	2	178	$794,327,849	$40,631,167
Petroleum Refining	3	394	$2,227,503,609	$112,266,182
Products of Petroleum and Coal, Not Elsewhere Classified	1	131	$742,501,203	$37,422,061
Crude Petroleum Pipelines	2	100	$43,142,673	$0
Natural Gas Transmission	1	121	$128,350,233	$0
Petroleum Bulk Stations and Terminals	2	50	$456,008,087	$9,028,960
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	1	25	$228,004,043	$4,514,480
Farm Supplies – Lawn and Garden Supplies Sold Via Retail Method	2	23	$24,393,453	$922,073
Total	**41**	**2,257**	**$6,951,492,947**	**$390,842,513**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; IMPLAN, 2023; BEA, 2023a.
[a] This represents the number of companies with facilities categorized within a given sector. Some companies have facilities categorized in different SIC code sectors. For this analysis, costs and profits for a company that has facilities across two or more SIC codes are split evenly across each SIC for that company's facilities.
[b] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

Table 32 shows the characteristics of the average firm affected by the potential amendments to Rule 4623. (Individual firms may be either larger or smaller than these average estimates.)

Table 32. Characteristics of Entities with Costs due to the Potential Amendments to Rule 4623—Storage of Organic Liquids

Sector	Average per Company			Average Annual Pay per Employee
	Employees	Revenue	Profits [a]	
Crude Petroleum and Natural Gas	41	$77,446,550	$6,245,290	$134,134
Natural Gas Liquids	31	$58,730,300	$4,736,011	$134,134
Industrial Organic Chemicals, NEC – Aliphatics	89	$397,163,925	$20,315,583	$128,917
Petroleum Refining	131	$742,501,203	$37,422,061	$136,442
Products of Petroleum and Coal, Not Elsewhere Classified	131	$742,501,203	$37,422,061	$136,442
Crude Petroleum Pipelines	50	$21,571,337	$0	$122,460
Natural Gas Transmission	121	$128,350,233	$0	$138,000
Petroleum Bulk Stations and Terminals	25	$228,004,043	$4,514,480	$81,814
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	25	$228,004,043	$4,514,480	$81,814
Farm Supplies – Lawn and Garden Supplies Sold Via Retail Method	11	$12,196,726	$461,036	$64,556
Average	**55**	**$169,548,608**	**$9,532,744**	**$131,512**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; RMA, 2023; IMPLAN, 2023.
[a] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

4.5.2 Compliance Cost Estimates

Compliance costs were estimated by SJVAPCD (2023), and include:

- One-time capital costs.
- Annual O&M costs beginning in 2024 and continuing indefinitely.

Total costs are calculated by annualizing the one-time capital costs that will be incurred in 2023 (for compliance by January 1, 2024) over a 10-year period using a 4 percent interest rate, and then summing annualized one-time costs and annualized costs to yield the total.

Table 33 shows the one-time, annual, and total annualized costs incurred by sector. Annualized costs would total approximately **$1,200,000** per year over 10 years, with the majority of costs incurred by the "Crude Petroleum and Natural Gas" sector.

Table 33. Costs of Compliance with Potential Amendments to Rule 4623—Storage of Organic Liquids

Sector	One-Time Capital Costs [a]	Annual O&M Costs [b]	Total Annualized Costs (Annualized One-Time + Annual) [c]
	2024	2024	2024
Crude Petroleum and Natural Gas	$183,161	$694,878	$716,591
Natural Gas Liquids	$26,711	$101,336	$104,503
Industrial Organic Chemicals, NEC – Aliphatics	$15,263	$57,906	$59,716
Petroleum Refining	$22,895	$86,860	$89,574
Products of Petroleum and Coal, Not Elsewhere Classified	$7,632	$28,953	$29,858
Crude Petroleum Pipelines	$15,263	$57,906	$59,716
Natural Gas Transmission	$3,816	$14,477	$14,929
Petroleum Bulk Stations and Terminals	$15,263	$57,906	$59,716
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	$7,632	$28,953	$29,858
Farm Supplies – Lawn and Garden Supplies Sold Via Retail Method	$15,263	$57,906	$59,716
Total	**$312,900**	**$1,187,083**	**$1,224,177**

Source: SJVAPCD, 2023.

[a] Includes one-time capital costs in 2024.

[b] Includes the increased costs to inspect, operate, and maintain equipment.

[c] The total annualized cost is calculated by summing annualized one-time costs (annualized over a 10-year period using a 4 percent discount rate) and annual costs.

4.5.3 Impacts on Affected Entities

This section first discusses our primary impacts test, which compares compliance costs to profits for affected companies. ERG then discusses indirect and induced impacts to related industries.

4.5.3.1 Direct Impacts

The primary measure of determining economic feasibility compares total annualized costs to profits for affected firms, and, as a sensitivity analysis to firm profits, with a threshold of 10 percent of profits indicating a finding of significant adverse impact (Berck, 1995). Therefore, ERG uses this comparison to aid in the District's determination of economic feasibility of the rule amendments.

As shown in Table 34, overall rule impacts comprise approximately **0.3 percent of profits**. Every sector for which ERG had sufficient profit data can expect these costs to be economically feasible. The sector with the highest costs as a percent of profits is the "Farm Supplies – Lawn and Garden Supplies Sold Via Retail Method" sector, incurring costs that are approximately **6.5 percent of profits**. As for the "Crude Petroleum Pipelines" and "Natural Gas Transmission" sectors, these sectors would need profit rates of less than 1.4 percent and 0.2 percent, respectively (which are both lower than any other profit rate derived from RMA for this analysis), for their industry-specific impact ratio to exceed 10 percent of profits. Those industries would have to already be losing tens or even hundreds of millions of dollars in order for the rule to be economically infeasible across all impacted companies.

Table 34. Economic Impacts for Entities Affected by Potential Amendments to Rule 4623—Storage of Organic Liquids

Sector	Average Annualized Cost per Company	Average Profits per Company [a]	Cost as % Profits
Crude Petroleum and Natural Gas	$27,561	$6,245,290	0.44%
Natural Gas Liquids	$20,901	$4,736,011	0.44%
Industrial Organic Chemicals, NEC – Aliphatics	$29,858	$20,315,583	0.15%
Petroleum Refining	$29,858	$37,422,061	0.08%
Products of Petroleum and Coal, Not Elsewhere Classified	$29,858	$37,422,061	0.08%
Crude Petroleum Pipelines	$29,858	$0	0.00%
Natural Gas Transmission	$14,929	$0	0.00%
Petroleum Bulk Stations and Terminals	$29,858	$4,514,480	0.66%
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	$29,858	$4,514,480	0.66%
Farm Supplies – Lawn and Garden Supplies Sold Via Retail Method	$29,858	$461,036	6.48%
Average	**$29,858**	**$9,532,744**	**0.31%**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.
[a] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

4.5.3.2 Employment, Indirect, and Induced Impacts

In addition to the primary test of direct impacts of costs on revenue, ERG also assessed potential direct impacts on employment, indirect impacts, and induced impacts using IMPLAN's (2023) input-output model. The IMPLAN model uses the direct costs of the rule to estimate "ripple effects" (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model" (IMPLAN, 2023). Outputs from the IMPLAN model include:

- **Direct employment impacts**, if facilities with compliance costs under the potential amendments were to attempt to offset these costs by reducing the number of employees.
- **Indirect revenue and employment impacts** that capture how directly affected firms might react to the direct cost of rule compliance by reducing purchases from their suppliers, and how those suppliers might in turn reduce employees.
- **Induced revenue and employment impacts** that capture how households will adjust their spending as a result of any changes in earnings.

Table 35 summarizes these impacts, which, taken together, may have a total impact on the District economy of approximately **$1,300,000 in revenue, with one job lost.**

Table 35. Direct, Indirect, and Induced Impacts of Potential Amendments to Rule 4623—Storage of Organic Liquids

Sector	Direct		Indirect		Induced		Total	
	Revenue (Costs)	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Crude Petroleum and Natural Gas	$716,591	0	$8,321	0	$76	0	$724,989	0
Natural Gas Liquids	$104,503	0	$8,321	0	$76	0	$112,900	0
Industrial Organic Chemicals, NEC – Aliphatics	$59,716	0	$82	0	$3	0	$59,800	0
Petroleum Refining	$89,574	0	$4,241	0	$354	0	$94,169	0
Products of Petroleum and Coal, Not Elsewhere Classified	$29,858	0	$51	0	$2	0	$29,912	0
Crude Petroleum Pipelines	$59,716	0	$4,600	0	$37	0	$64,352	0
Natural Gas Transmission	$14,929	0	$5,997	0	$624	0	$21,549	0
Petroleum Bulk Stations and Terminals	$59,716	0	$4,241	0	$354	0	$64,311	0
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	$29,858	0	$9,209	0	$729	0	$39,796	0
Farm Supplies – Lawn and Garden Supplies Sold Via Retail Method	$59,716	0	$833	0	$713	0	$61,262	0
Total	**$1,224,177**	**1**	**$45,897**	**0**	**$2,967**	**0**	**$1,273,041**	**1**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.

Note: Totals may not equal presented counts of revenue and employment for each sector due to rounding.

Table 36 compares these impacts to the total size of the District's economy (as estimated in the IMPLAN model). These impacts represent **less than 0.001 percent** of revenue and employment District-wide.

Table 36. Comparison of Total Impacts against the District-Wide Economy for Potential Amendments to Rule 4623—Storage of Organic Liquids Processing Facilities

	Total Rule Impacts	Size of District Economy [a]	% of District Economy
Revenue	$1,273,041	$368,710,597,792	0.000%
Employment	1	1,982,068	0.000%

Source: ERG estimates based on IMPLAN, 2023.

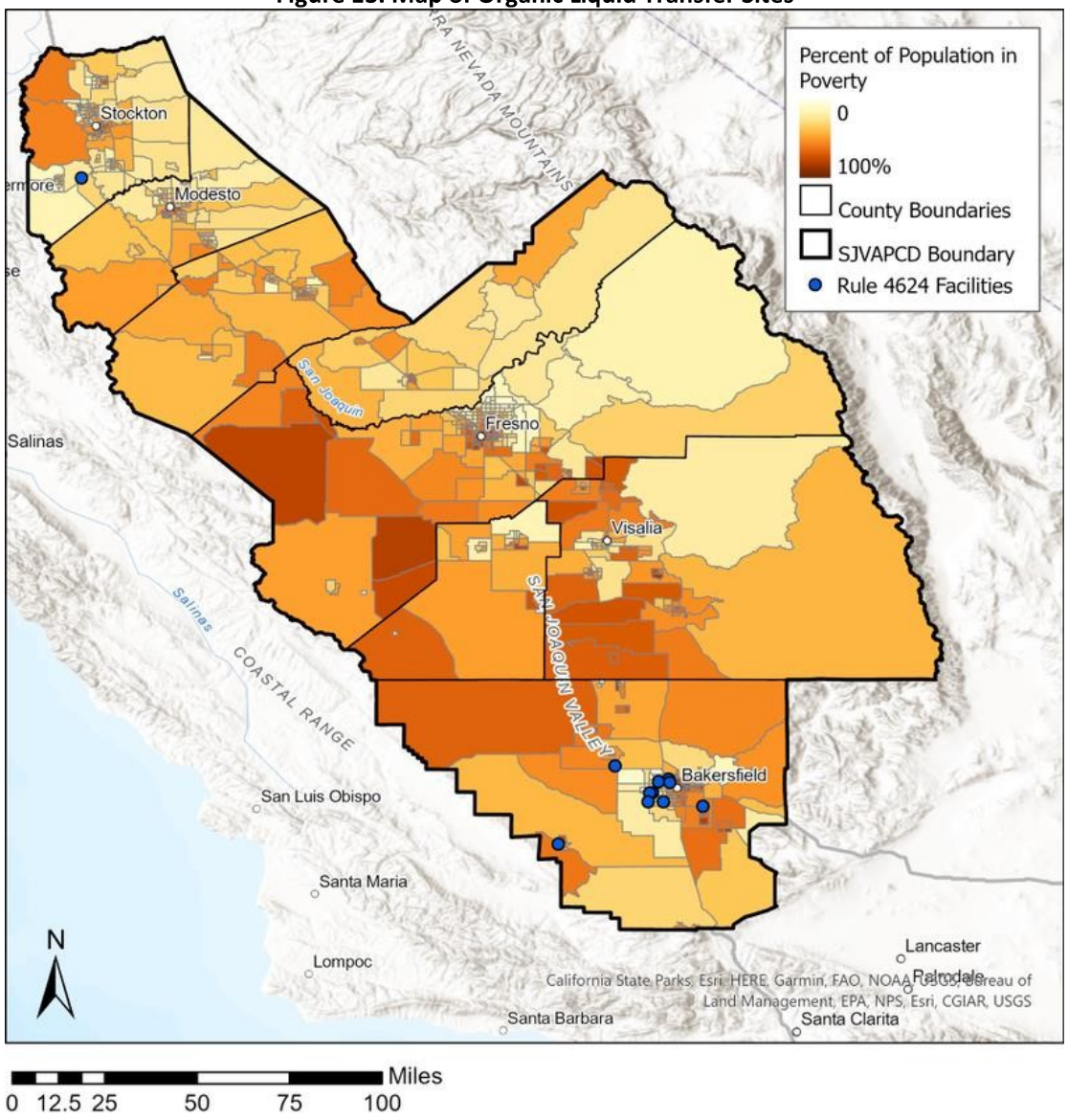
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

4.6 RULE 4624 – TRANSFER OF ORGANIC LIQUID

4.6.1 Profile of Affected Entities

Figure 13 presents a map of the organic liquid transfer facilities. Facilities were mapped using ArcGIS Pro 2.6.0. Out of 54 facilities provided, only 18 of them provided sufficient information to be mapped, with 11 of unique addresses mapped. The majority of facilities are located in and around Bakersfield. One facility is located on the western border of Kern County, with another located in San Joaquin County.

Figure 13. Map of Organic Liquid Transfer Sites



Source data: SJVAPCD, 2023.
Map created by ERG using ArcGIS® software by Esri.

Table 37 includes a profile of firms affected by the potential amendments to Rule 4624 (i.e., those that will incur compliance costs). A total of 39 firms will incur costs. Note that some companies have facilities across two or more sectors. For those companies, ERG evenly distributed the number employees, revenues, and profits between the relevant sectors.

Table 37. Profile of Entities Affected by Potential Amendments to Rule 4624—Transfer of Organic Liquid

Sector	Total Companies [a]	Total, All Companies		
		Employees	Revenue	Profits [b]
Crude Petroleum and Natural Gas	7	225	$419,502,145	$33,828,653
Natural Gas Liquids	7	225	$419,502,145	$33,828,653
Industrial Organic Chemicals, NEC – Aliphatics	4	271	$897,981,141	$47,049,378
Nitrogenous Fertilizers	1	24	$16,789,494	$991,252
Petroleum Refining	4	459	$2,598,754,211	$130,977,212
Products of Petroleum and Coal, Not Elsewhere Classified	1	131	$742,501,203	$37,422,061
Special Warehousing and Storage, Not Elsewhere Classified	1	22	$12,244,129	$766,972
Crude Petroleum Pipelines	6	300	$129,428,020	$0
Transportation Services, Not Elsewhere Classified	1	9	$1,573,010	$104,762
Natural Gas Transmission	2	484	$513,400,932	$0
Chemicals and Allied Products, NEC	1	15	$17,735,877	$753,420
Petroleum Bulk Stations and Terminals	7	199	$1,389,595,597	$27,086,880
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	2	37	$342,006,065	$6,771,720
Total	**39**	**2,401**	**$7,501,013,969**	**$319,580,964**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; IMPLAN, 2023; BEA, 2023A.

[a] This represents the number of companies with facilities categorized within a given sector. Some companies have facilities categorized in different SIC code sectors. For this analysis, costs and profits for a company that has facilities across two or more SIC codes are split evenly across each SIC for that company's facilities.

[b] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

Table 38 shows the characteristics of the average firm affected by the potential amendments to Rule 4624. (Individual firms maybe either larger or smaller than these average estimates.)

Table 38. Characteristics of Entities with Costs due to the Potential Amendments to Rule 4624—Transfer of Organic Liquid

Sector	Average per Company			Average Annual Pay per Employee
	Employees	Revenue	Profits [a]	
Crude Petroleum and Natural Gas	32	$59,928,878	$4,832,665	$134,134
Natural Gas Liquids	32	$59,928,878	$4,832,665	$134,134
Industrial Organic Chemicals, NEC – Aliphatics	68	$224,495,285	$11,762,345	$121,615
Nitrogenous Fertilizers	24	$16,789,494	$991,252	$78,977
Petroleum Refining	115	$649,688,553	$32,744,303	$136,442
Products of Petroleum and Coal, Not Elsewhere Classified	131	$742,501,203	$37,422,061	$136,442
Special Warehousing and Storage, Not Elsewhere Classified	22	$12,244,129	$766,972	$73,712
Crude Petroleum Pipelines	50	$21,571,337	$0	$122,460
Transportation Services, Not Elsewhere Classified	9	$1,573,010	$104,762	$42,456
Natural Gas Transmission	242	$256,700,466	$0	$138,000
Chemicals and Allied Products, NEC	15	$17,735,877	$753,420	$90,192
Petroleum Bulk Stations and Terminals	28	$198,513,657	$3,869,554	$92,014
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	19	$171,003,033	$3,385,860	$81,814
Average	**62**	**$192,333,692**	**$8,194,384**	**$126,594**

Sources: ERG estimates based on SJVAPCD, 2023; NAICS.com, 2021; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; RMA, 2023; IMPLAN, 2023.
[a] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

4.6.2 Compliance Cost Estimates

Compliance costs were estimated by SJVAPCD (2023), and include O&M costs beginning in 2024 and continuing indefinitely. Table 39 shows the annual O&M costs incurred by sector. Annual costs would total about **$150,000** per year.

Table 39. Costs of Compliance with Potential Amendments to Rule 4624—Transfer of Organic Liquid

Sector	Annual O&M Costs [a]	Total Annual Costs
	2024	2024
Crude Petroleum and Natural Gas	$18,990	$18,990
Natural Gas Liquids	$18,990	$18,990
Industrial Organic Chemicals, NEC – Aliphatics	$15,192	$15,192
Nitrogenous Fertilizers	$3,798	$3,798
Petroleum Refining	$13,293	$13,293
Products of Petroleum and Coal, Not Elsewhere Classified	$3,798	$3,798
Special Warehousing and Storage, Not Elsewhere Classified	$3,798	$3,798
Crude Petroleum Pipelines	$22,788	$22,788
Transportation Services, Not Elsewhere Classified	$3,798	$3,798
Natural Gas Transmission	$7,596	$7,596
Chemicals and Allied Products, NEC	$3,798	$3,798
Petroleum Bulk Stations and Terminals	$26,586	$26,586
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	$5,697	$5,697
Total	**$148,120**	**$148,120**

Source: SJVAPCD, 2023.

[a] Includes the increased costs to inspect, operate, and maintain equipment.

4.6.3 Impacts on Affected Entities

This section first discusses our primary impacts test, which compares compliance costs to profits for affected companies. ERG then discusses indirect and induced impacts to related industries.

4.6.3.1 Direct Impacts

Our primary measure of determining economic feasibility is a comparison of total annual costs to profits for affected firms; a threshold of 10 percent of profits indicates a finding of significant adverse impact (Berck, 1995). Therefore, ERG uses this comparison to aid in the District's determination of economic feasibility of the rule amendments.

As shown in Table 40, overall rule impacts are approximately **0.05 percent of profits**. Every sector for which ERG had sufficient profit data can expect these costs to be economically feasible. The sector with the highest costs as a percent of profits is the "Transportation Services, Not Elsewhere Classified" sector, incurring costs that are approximately **3.6 percent of profits**. As for the "Crude Petroleum Pipelines" and "Natural Gas Transmission" sectors, these sectors would need profit rates of less than 0.2 percent and

0.02 percent, respectively (which are both lower than any other profit rate derived from RMA for this analysis), for their industry-specific impact ratio to exceed 10 percent of profits. Those industries would have to be operating at a nearly 50 percent loss in order for the rule to be economically infeasible across all impacted companies.

Table 40. Economic Impacts for Entities Affected by Potential Amendments to Rule 4624—Transfer of Organic Liquid

Sector	Average Annual Cost per Company	Average Profits per Company [a]	Cost as % Profits
Crude Petroleum and Natural Gas	$2,713	$4,832,665	0.06%
Natural Gas Liquids	$2,713	$4,832,665	0.06%
Industrial Organic Chemicals, NEC – Aliphatics	$3,798	$11,762,345	0.03%
Nitrogenous Fertilizers	$3,798	$991,252	0.38%
Petroleum Refining	$3,323	$32,744,303	0.01%
Products of Petroleum and Coal, Not Elsewhere Classified	$3,798	$37,422,061	0.01%
Special Warehousing and Storage, Not Elsewhere Classified	$3,798	$766,972	0.50%
Crude Petroleum Pipelines	$3,798	$0	0.00%
Transportation Services, Not Elsewhere Classified	$3,798	$104,762	3.63%
Natural Gas Transmission	$3,798	$0	0.00%
Chemicals and Allied Products, NEC	$3,798	$753,420	0.50%
Petroleum Bulk Stations and Terminals	$3,798	$3,869,554	0.10%
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	$2,848	$3,385,860	0.08%
Average	**$3,798**	**$8,194,384**	**0.05%**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.
[a] RMA does not have financial data available for either the Crude Petroleum Pipelines sector or the Natural Gas Transmission sector. ERG assumed zero percent profit to present an abundantly conservative estimate of impacts.

4.6.3.2 Employment, Indirect, and Induced Impacts

In addition to the primary test of direct impacts of costs on revenue, ERG also assessed potential direct impacts on employment, indirect impacts, and induced impacts using IMPLAN's (2023) input-output model. The IMPLAN model uses the direct costs of the rule to estimate "ripple effects" (specifically backward linkages) of a given economic activity within a specific geographic area through the implementation of its Input-Output model" (IMPLAN, 2023).

Outputs from the IMPLAN model include:

- **Direct employment impacts**, if facilities with compliance costs under the potential amendments were to attempt to offset these costs by reducing the number of employees.

- **Indirect revenue and employment impacts** that capture how directly affected firms might react to the direct cost of rule compliance by reducing purchases from their suppliers, and how those suppliers might in turn reduce employees.
- **Induced revenue and employment impacts** that capture how households will adjust their spending as a result of any changes in earnings.

Table 41 summarizes these impacts, which, taken together, may have a total impact on the District economy of about **$160,000 in revenue, with as few as zero jobs lost.**

Table 41. Direct, Indirect, and Induced Impacts of Potential Amendments to Rule 4624—Transfer of Organic Liquid

Sector	Direct		Indirect		Induced		Total	
	Revenue (Costs)	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment	Revenue	Employ-ment
Crude Petroleum and Natural Gas	$18,990	0	$1,898	0	$11	0	$20,899	0
Natural Gas Liquids	$18,990	0	$1,898	0	$11	0	$20,899	0
Industrial Organic Chemicals, NEC – Aliphatics	$15,192	0	$18	0	$0	0	$15,210	0
Nitrogenous Fertilizers	$3,798	0	$163	0	$1	0	$3,962	0
Petroleum Refining	$13,293	0	$805	0	$52	0	$14,150	0
Products of Petroleum and Coal, Not Elsewhere Classified	$3,798	0	$9	0	$0	0	$3,807	0
Special Warehousing and Storage, Not Elsewhere Classified	$3,798	0	$274	0	$60	0	$4,133	0
Crude Petroleum Pipelines	$22,788	0	$756	0	$5	0	$23,549	0
Transportation Services, Not Elsewhere Classified	$3,798	0	$106	0	$67	0	$3,971	0
Natural Gas Transmission	$7,596	0	$2,144	0	$92	0	$9,832	0
Chemicals and Allied Products, NEC	$3,798	0	$9	0	$0	0	$3,807	0
Petroleum Bulk Stations and Terminals	$26,586	0	$805	0	$52	0	$27,443	0
Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	$5,697	0	$2,124	0	$107	0	$7,929	0
Total	**$148,120**	**0**	**$11,010**	**0**	**$460**	**0**	**$159,590**	**0**

Sources: ERG estimates based on SJVAPCD, 2023; U.S. Census Bureau, 2020a; U.S. Census Bureau, 2020c; NAICS.com, 2021; RMA, 2023; IMPLAN, 2023.

Note: Totals may not equal presented counts of revenue and employment for each sector due to rounding.

Table 42 compares these impacts to the total size of the District's economy (as estimated in the IMPLAN model). These impacts represent **less than 0.001 percent** of revenue and employment District-wide.

Table 42. Comparison of Total Impacts against the District-Wide Economy for Potential Amendments to Rule 4624—Transfer of Organic Liquid

	Total Rule Impacts	Size of District Economy [a]	% of District Economy
Revenue	$159,590	$368,710,597,792	0.000%
Employment	0	1,982,068	0.000%

Source: ERG estimates based on IMPLAN, 2023.

[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

5 IMPACTS ON SMALL ENTITIES

The entities affected by the potential amendments may include small entities (i.e., small businesses and/or small government entities).

For private entities, a small business is defined in the California Small Business Procurement and Contract Act (Cal. Gov't Code § 14837) as an independently owned and operated, non-dominant business with principal office located in California, fewer than 100 employees and earning less than $15 million in revenues.

The average firm revenue and employment figures presented for each rule in Table 14, Table 20, Table 26, Table 32, and Table 38 suggest some affected firms may be small. Although individual firms may be larger or smaller than the averages shown in the tables, there is little information available on which to base a definitive conclusion. Furthermore, even if it is possible to determine a specific firm earns less than $15 million in revenues and employs fewer than 100 employees, the designation of "small business" not only requires that the firm meets the revenue and employment size standards, but also has its principal office located in California.

To characterize the likelihood of small business impacts:

- Rule 4401 (Steam-Enhanced Crude Oil Production Wells): it is unlikely that firms are small, and firm level impacts are less than 1 percent of revenues.
- Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, And Natural Gas Processing Facilities): while there are some small firms, firm level costs for these firms are expected to be much lower than the average firm.
- Rule 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants): it is unlikely that firms are small, and firm level impacts are less than 1 percent of revenues.
- Rule 4623 (Storage of Organic Liquids): it is possible that 2 affected firms in the "Farm Supplies – Lawn and Garden Supplies Sold Via Retail Method" sector are small businesses based on industry average revenues. While estimated average annualized compliance costs are about $29,900 per firm, costs for small firms will be significantly lower.
- Rule 4624 (Transfer of Organic Liquids): it is possible, based on industry average revenues, that one affected firm in the "Special Warehousing and Storage, Not Elsewhere Classified" sector and one affected firm in the "Transportation Services, Not Elsewhere Classified" sector are small businesses. The estimated annual compliance costs under rule 4624 are a little less than $3,800 per firm though, and impacts presented in Table 40 for both of those sectors are well under the 10 percent of profits threshold to determine economic feasibility (0.5 percent and 3.6 percent, respectively).

Although economic feasibility is based on an evaluation of overall impacts to all affected firms covered by a rule, to be responsive to California's Small Business requirements, we more closely examined four potentially small businesses that may incur substantial impacts. Two companies are affected by Rule 4623, the other two by Rule 4624. Both facilities affected by Rule 4623 are captured

within the "Farm Supplies - Lawn and Garden Supplies Sold Via Retail Method" sector. Upon review, they both appear to be connected with other companies through common ownership, which may therefore provide additional resources beyond its immediate revenues to cover expected compliance costs. As for the two companies affected by Rule 4624, one is categorized within the "Special Warehousing and Storage, Not Elsewhere Classified" sector, while the other is in the "Transportation Services, Not Elsewhere Classified" sector. Like the two companies looked at under Rule 4623, the "Warehousing" company is also linked to other companies through common ownership. The "Transportation" company may also have similar linkages to other companies that might provide additional resources beyond its immediate revenues to cover expected compliance costs. Compliance costs were estimated on a pretax basis, but are compared to post-tax profits; adjusting compliance costs for taxes should reduce costs and impacts.

In summary, the District is revising five rules affecting 157 unique facilities owned by 91 unique firms. Rule 4455 and Rule 4624 are expected to impose compliance costs averaging less than 0.1 percent of firm profits. Rule 4623 is expected to impose compliance costs of less than 1 percent of firm profits. The compliance costs for Rule 4401 are expected to average approximately 2 percent of profits for impacted firms, while impacts for Rule 4409 are expected to make up under 4 percent of profits. Based on average firm characteristics, few are likely to be small by California's definition, and the vast majority of those likely to be small generally show impacts consistent with the overall impacts of the rules.

The analysis of each rule includes a map showing the distribution of affected facilities overlaid on a map showing the percentage of the population living in poverty. The maps demonstrate that a few affected facilities are located in regions with high poverty rates. However, because the analyses demonstrate that the rules are economically feasible, with most facilities incurring costs less than 1 percent of profits, and in many cases negligible costs, there should not be substantial impacts in high poverty areas of the District.

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APPENDIX A - SECTOR, SIC CODE, AND NAICS CODE CONCORDANCES

Table A-1 shows the concordance between SIC codes and sectors developed by SJV APCD. (SIC codes that were not in the original concordance but that might have indirect and induced impacts were assigned the sector "Other Industries.")

Table A-1. SIC Code to Sector Concordance used to Analyze the Impacts of Rules 4401, 4409, 4455, 4623, and 4624—Steam-Enhanced Crude Oil Production Wells; Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities; Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants; Storage of Organic Liquids; and Transfer of Organic Liquid

SIC Code	SIC Industry	Rule 4401	Rule 4409	Rule 4455	Rule 4623	Rule 4624
1311	Crude Petroleum and Natural Gas	x	x		x	x
1321	Natural Gas Liquids		x	x	x	x
2869	Industrial Organic Chemicals, NEC – Aliphatics			x	x	x
2873	Nitrogenous Fertilizers					x
2879	Pesticides and Agricultural Chemicals, NEC			x		
2911	Petroleum Refining			x	x	x
2999	Products of Petroleum and Coal, Not Elsewhere Classified				x	x
4226	Special Warehousing and Storage, Not Elsewhere Classified					x
4612	Crude Petroleum Pipelines				x	x
4789	Transportation Services, Not Elsewhere Classified					x
4922	Natural Gas Transmission		x		x	x
5169	Chemicals and Allied Products, NEC			x		x
5171	Petroleum Bulk Stations and Terminals				x	x
5172	Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals				x	x
5191	Farm Supplies - Lawn and Garden Supplies Sold Via Retail Method				x	

Source: SJVAPCD, 2023.

Table A-2 shows the NAICS codes that map to the SIC codes used in the analysis (limited to the NAICS codes assigned to the facilities in the District that may be affected by the potential amendments). This concordance was primarily developed using the U.S. Census Bureau's (2020d) SIC to NAICS concordances. Where multiple NAICS codes map to one SIC code, ERG used information on companies' websites or other search tools about what type of industry they are engaged in to assign a NAICS code.

Table A-2. SIC to NAICS Concordance for Facilities that may be Affected by Potential Amendments to Rules 4401, 4409, 4455, 4623, and 4624—Steam-Enhanced Crude Oil Production Wells; Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities; Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants; Storage of Organic Liquids; and Transfer of Organic Liquid

SIC Code	SIC Industry	Corresponding NAICS
1311	211120 (Crude Petroleum Extraction)	211120 (Crude Petroleum Extraction)
1321	211130 (Natural Gas Extraction)	211130 (Natural Gas Extraction)
2869	325110, 325120, 325180, 325193, 325194, 325199, 325998 (Petrochemical Manufacturing, Industrial Gas Manufacturing, Other Basic Inorganic Chemical Manufacturing, Ethyl Alcohol Manufacturing, Cyclic Crude, Intermediate, and Gum and Wood Chemical Manufacturing, All Other Basic Organic Chemical Manufacturing, All Other Miscellaneous Chemical Product and Preparation Manufacturing)	325110, 325120, 325180, 325193, 325194, 325199, 325998 (Petrochemical Manufacturing, Industrial Gas Manufacturing, Other Basic Inorganic Chemical Manufacturing, Ethyl Alcohol Manufacturing, Cyclic Crude, Intermediate, and Gum and Wood Chemical Manufacturing, All Other Basic Organic Chemical Manufacturing, All Other Miscellaneous Chemical Product and Preparation Manufacturing)
2873	325311 (Nitrogenous Fertilizers)	325311 (Nitrogenous Fertilizers)
2879	325320 (Pesticide and Other Agricultural Chemical Manufacturing)	325320 (Pesticide and Other Agricultural Chemical Manufacturing)
2911	324110 (Petroleum Refineries)	324110 (Petroleum Refineries)
2999	324199 (All Other Petroleum and Coal Products Manufacturing)	324199 (All Other Petroleum and Coal Products Manufacturing)
4226	493110, 493120, 493190 (General Warehousing and Storage, Refrigerated Warehousing and Storage, Other Warehousing and Storage)	493110, 493120, 493190 (General Warehousing and Storage, Refrigerated Warehousing and Storage, Other Warehousing and Storage)
4612	486110 (Pipeline Transportation of Crude Oil)	486110 (Pipeline Transportation of Crude Oil)
4789	487110, 488210, 488999, 722310 (Scenic and Sightseeing Transportation, Land, Support Activities for Rail Transportation, All Other Support Activities for Transportation, Food Service Contractors)	487110, 488210, 488999, 722310 (Scenic and Sightseeing Transportation, Land, Support Activities for Rail Transportation, All Other Support Activities for Transportation, Food Service Contractors)
4922	486210 (Pipeline Transportation of Natural Gas)	486210 (Pipeline Transportation of Natural Gas)
5169	424690, 425110, 425120 (Other Chemical and Allied Products Merchant Wholesalers, Business to Business Electronic Markets, Wholesale Trade Agents and Brokers)	424690, 425110, 425120 (Other Chemical and Allied Products Merchant Wholesalers, Business to Business Electronic Markets, Wholesale Trade Agents and Brokers)
5171	424710, 454310 (Petroleum Bulk Stations and Terminals, Fuel Dealers)	424710, 454310 (Petroleum Bulk Stations and Terminals, Fuel Dealers)

Table A-2. SIC to NAICS Concordance for Facilities that may be Affected by Potential Amendments to Rules 4401, 4409, 4455, 4623, and 4624—Steam-Enhanced Crude Oil Production Wells; Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities; Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants; Storage of Organic Liquids; and Transfer of Organic Liquid

SIC Code	SIC Industry	Corresponding NAICS
5172	424720, 425110, 425120 (Petroleum and Petroleum Products Merchant Wholesalers (except Bulk Stations and Terminals), Business to Business Electronic Markets, Wholesale Trade Agents and Brokers)	424720, 425110, 425120 (Petroleum and Petroleum Products Merchant Wholesalers (except Bulk Stations and Terminals), Business to Business Electronic Markets, Wholesale Trade Agents and Brokers)
5191	424910, 425110, 425120, 444220 (Farm Supplies Merchant Wholesalers, Business to Business Electronic Markets, Wholesale Trade Agents and Brokers, Nursery, Garden Center, and Farm Supply Stores)	424910, 425110, 425120, 444220 (Farm Supplies Merchant Wholesalers, Business to Business Electronic Markets, Wholesale Trade Agents and Brokers, Nursery, Garden Center, and Farm Supply Stores)

Source: SJVAPCD, 2023.

APPENDIX E

Rule Consistency Analysis for Proposed Amendments to Rules 4401, 4409, 4455, 4623 and 4624

June 15, 2023

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RULE CONSISTENCY ANALYSIS FOR PROPOSED RULES 4401, 4409, 4455, 4623, and 4624

I. REQUIREMENTS OF ANALYSIS

Pursuant to Section 40727.2 of the California Health and Safety Code, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of the rule, or regulation, with corresponding elements of existing or proposed District and U.S. Environmental Protection Agency (EPA) rules, regulations, and guidelines that apply to the same source category. The rule elements analyzed are emission limits or control efficiency, operating parameters and work practices, monitoring and testing, and recordkeeping and reporting requirements.

II. RULE CONSISTENCY ANALYSIS

A. District Rules

Components of Leak Detection and Repair Rules 4401, 4409, 4455, 4623, and 4624 could be subject to other District rules including:

- Rule 2520 (Federally Mandated Operating Permits),
- Rule 2201 (New and Modified Stationary Source Review Rule),

The above-listed rules are not in conflict nor are they inconsistent with the requirements of Proposed Rules 4401, 4409, 4455, 4623, 4624.

B. Federal EPA Rules and Regulations

Rule 4401 (Steam-Enhanced Crude oil Production Wells)

1. EPA Control Techniques Guidelines (CTG)

- EPA- 453/B-16-001 2016/10 (Control Techniques Guidelines for Oil and Natural Gas Industry)

This CTG applies to equipment used in the oil and gas industry, including crude oil production wells and components subject to Rule 4401. The District evaluated the requirements of the CTG and determined that with the proposed amendments, there are no conflicts or inconsistencies with Rule 4401.

2. Alternative Control Techniques (ACT)

- EPA 1992 ACT Document for Control Techniques for VOC Emissions from Stationary Sources (EPA-453/R-92-018 1992/12)

This document outlines the various control techniques and emission reductions that would occur at a variety of facilities, including oil and gas facilities. The control techniques are similar to the requirements for Rule 4401 including vapor control systems, and leak detection and repair. The District evaluated the requirements contained within the ACT and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4401.

3. Federal New Source Performance Standards (NSPS)

- 40 CFR Part 60, Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015
- 40 CFR Part 60, Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

These NSPS are applicable to oil and gas facilities for which Construction, Modification, or Reconstruction Commenced 8/23/11 - 9/18/15, and after 9/18/15 respectively. The NSPS impose equipment standards on several different types of new/modified/reconstructed equipment and imposes leak detection and repair requirements for such equipment. It is important to note that the NSPS are not retrofit requirements for existing, unmodified equipment. The District evaluated the requirements of the NSPS and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4401.

4. National Emission Standards for Hazardous Air Pollutants (NESHAPs) and Maximum Achievable Control Technologies (MACTs)

- 40 CFR 63 Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities (2012/08)
- 40 CFR 63 Subpart UU—National Emission Standards for Equipment Leaks—Control Level 2 Standards (2002/07)

Both NESHAPs establish leak standards for oil and gas production facilities as well as general equipment leaks. The District evaluated the requirements of the NESHAPs and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4401.

Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities)

1. EPA Control Techniques Guidelines (CTG)

- EPA-450/3-83-007 (Control Techniques Guidelines for Control of Volatile Organic Compound Equipment Leaks from Natural Gas/ Gasoline Processing Plants)

This CTG applies to equipment used in the oil and gas industry, including crude oil production wells and components subject to Rule 4409. California Air Resources Board (CARB) submitted to EPA, for inclusion into the State Implementation Plan (SIP) a proposal that demonstrated that the CARB oil and gas methane rule in addition to District Rules 4401, 4409, 4623, when implemented together would satisfy the EPA's CTG for the oil and natural gas industry. The District evaluated the requirements of the CTG and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4409.

- EPA- 453/B-16-001 2016/10 (Control Techniques Guidelines for Oil and Natural Gas Industry)

This CTG applies to equipment used in the oil and gas industry, including crude oil production wells and components subject to Rule 4409. The District evaluated the requirements of the CTG and determined that with the proposed amendments, there are no conflicts or inconsistencies with Rule 4409.

2. Alternative Control Techniques (ACT)

- EPA 1992 ACT Document for Control Techniques for VOC Emissions from Stationary Sources (EPA-453/R-92-018 1992/12)

This document outlines the various control techniques and emission reductions for equipment leaks from natural gas/gasoline processing plants establishes the Reasonably Available Control Technology (RACT) standards for these source categories. In general, the ACT establishes periodic inspections of components, a specified leak threshold, and a time frame to repair leaking components. The District evaluated the requirements of the ACT and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4409.

3. Federal New Source Performance Standards (NSPS)

- 40 CFR Part 60, Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015
- 40 CFR Part 60, Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

These NSPS are applicable to oil and gas facilities for which Construction, Modification, or Reconstruction Commenced 8/23/11 - 9/18/15, and after 9/18/15 respectively. The NSPS impose equipment standards on several different types of new/modified/reconstructed equipment and imposes leak detection and repair requirements for such equipment. It is important to note that the NSPS are not retrofit requirements for existing, unmodified equipment.

The District evaluated the requirements of the NSPS and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4409.

4. National Emission Standards for Hazardous Air Pollutants (NESHAPs) and Maximum Achievable Control Technologies (MACTs)

- 40 CFR 60 Subpart KKK (Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants)
- 40 CFR 60 Subpart VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing)
- 40 CFR 60 Subpart GGG (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries)

40 CFR 60 Subpart KKK applies to onshore natural gas processing plants that commence construction, reconstruction, or modification after January 20, 1984. A compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by this subpart if it is located at an onshore natural gas processing plant. If the unit is not located at the plant site, then it is exempt from the provisions of this subpart.

The federal SOCMI rule covers industries that produce, as intermediates or final products listed in 40 CFR Part 60 Section 60.489. The standards apply to any affected facility that commenced construction or modification after January 5, 1981.

40 CFR 60 Subpart GGG applies to petroleum refineries that commenced construction or modification after January 4, 1983. Facilities that are subject to 40 CFR 60 Subpart VV or 40 CFR 60 Subpart KKK are excluded from 40 CFR 60 Subpart GGG. The District evaluated the requirements of the NESHAPs and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4409.

Rule 4455 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities)

1. EPA Control Techniques Guidelines (CTG)

- EPA-450/2-78-036 1978/06 (Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment)
- EPA-450/3-83-007 1983/12 (Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants)
- EPA-450/3-84-015 1984/12 (Control of Volatile Organic Compound Emissions from Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry)

The District evaluated the requirements of the CTGs and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4455.

2. Alternative Control Techniques (ACT)

- EPA 1992 ACT Document for Control Techniques for VOC Emissions from Stationary Sources (EPA-453/R-92-018 1992/12)

This document outlines the various control techniques and emission reductions for equipment leaks from natural gas/gasoline processing plants establishes the RACT standards for these source categories. In general, the ACT establishes periodic inspections of components, a specified leak threshold, and a time frame to repair leaking components. The District evaluated the requirements of the ACT and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4455.

3. Federal New Source Performance Standards (NSPS)

- 40 CFR Part 60, Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015
- 40 CFR Part 60, Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (2008/06)

40 CFR Part 60, Subpart OOOO contains a valve leak limit of 500 ppmv, compared to the 400 ppmv limit in Rule 4455. When comparing these limits, the requirements of Rule 4455 are as stringent as or more stringent than the requirements in the NSPS. All other components in Rule 4455 are as stringent as the NSPS.

With 40 CFR Part 60, Subpart GGGa, District Rule 4455 has broader applicability as it applies to all equipment at refineries, not only new/reconstructed/modified equipment. NSPS Subpart GGGa only applies to new/reconstructed/modified equipment and it has higher leak repair thresholds than District Rule 4455.

The District evaluated the requirements of the NSPS and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4455.

4. National Emission Standards for Hazardous Air Pollutants (NESHAPs) and Maximum Achievable Control Technologies (MACTs)

- 40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (2013/06
- 40 CFR 63 Subpart HH - National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Facilities (2012/08)

40 CFR 63 Subpart CC applies to petroleum refining process units and to related emissions points. The subpart establishes emission limits and work practice standards for petroleum refining process units to regulate hazardous air pollutants. The basic requirements of this NESHAP are that the components do not contain leaks, defined as 1,000 ppmv (500 ppmv for pressure relief devices). The NESHAP applies to any petroleum refining process unit that is a major HAP source.

The federal SOCMI rule covers industries that produce, as intermediates or final products listed in 40 CFR Part 60 Section 60.489. The standards apply to any affected facility that commenced construction or modification after January 5, 1981.

The District evaluated the requirements of the NESHAPs and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4455.

Rule 4623 (Storage of Organic Liquids)

1. EPA Control Techniques Guidelines (CTG)

- EPA-450/2-77-036 1977/12 (Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed-Roof Tanks)

This CTG applies to fixed roof storage tanks with capacities greater than 39,626 gallons containing petroleum liquids with a true vapor pressure (TVP) greater than 1.5 psia. This CTG states that the recommended RACT for fixed roof tanks that used for the storage of petroleum liquids, is retrofitting with the following: internal floating roofs equipped with a closure seal or seals, or alternative equivalent control; and the seal closure device shall be no visible holes, tears, or other openings in the seal or any seal fabric.

The District evaluated the requirements of the CTG and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4623.

- EPA-450/2-78-047 1978/12 (Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks)

This CTG applies to external floating roof tanks with capacities greater than 39,626 gallons containing petroleum liquids with a TVP greater than 1.5 psia. This CTG states that the recommended RACT for external floating roof tanks that used for the storage of petroleum liquids, is retrofitting with a continuous secondary seal extending from the floating roof to the tank wall (a rim-mounted secondary) for the following type of tanks: a welded tank that stores petroleum liquid with TVP equal to 4.0 psia is greater, which the primary seal is a metallic-type seal, a liquid-mounted foam seal, a liquid mounted liquid-filled type seal, or its equivalent closure device; a riveted tank that stores petroleum liquid with TVP equal to 1.5 psia or greater, which the primary seal is a metallic-type seal, a liquid-mounted foam seal, a liquid mounted liquid-filled type seal, or its equivalent closure device; either a welded or riveted tank that stores petroleum liquid with TVP greater than 1.5 psia, which the primary seal is vapor-mounted; the seal closure device shall be no visible holes, tears, or other openings in the seal or any seal fabric.

The District evaluated the requirements of the CTG and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4623.

- EPA- 453/B-16-001 2016/10 (Control Techniques Guidelines for Oil and Natural Gas Industry)

This CTG applies to equipment used in the oil and gas industry, including crude oil production wells and components subject to Rule 4623. The District evaluated the requirements of the CTG and determined that with the proposed amendments, there are no conflicts or inconsistencies with Rule 4623.

2. Alternative Control Techniques (ACT)

- EPA 1992 ACT Document for Control Techniques for VOC Emissions from Stationary Sources (EPA-453/R-92-018 1992/12)

This document outlines the various control techniques and emission reductions that would occur at a variety of facilities, including organic liquid storage tanks. The control techniques are similar to the requirements for Rule 4623 including vapor control system requirement. The District evaluated the requirements of the ACT and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4623.

- EPA 1994 ACT Document for Control Techniques Document for Volatile Organic Liquid Storage In Floating and Fixed Roof Tanks (EPA-453/R-94-001 1994/01)

The document outlines various control techniques and emission reductions that would occur at a variety of facilities, including organic liquid storage tanks. The District evaluated the requirements of the ACT and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4623.

3. Federal New Source Performance Standards (NSPS)

- 40 CFR 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after June 11, 1973, and Prior to May 19, 1978
- 40 CFR 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984
- 40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

The District evaluated the requirements of the NSPS and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4623.

4. National Emission Standards for Hazardous Air Pollutants (NESHAPs) and Maximum Achievable Control Technologies (MACTs)

- 40 CFR 63 Subpart EEEE - Organic Liquids Distribution (Non-Gasoline) (2020/03)
- 40 CFR 63 Subpart BBBBBB - Gasoline Distribution Facilities (Bulk Gasoline Terminal and Pipeline Breakout Station) (2011/01)

NESHAP 40 CFR 63 Subpart EEEE requires emissions from storage tank with capacity greater than 5,000 gallons be routed through a closed vent system into any combination of control devices achieving at least 95 weight-percent HAP reduction, or a reduction to an exhaust concentration less than or equal to 20 ppmv (control devices must meet applicable testing, monitoring and operating standards depending on type of device).

NESHAP 40 CFR 63 Subpart BBBBBB requires the following gasoline storage tanks be equipped with a fixed roof that is mounted to the storage tank in a stationary manner, and maintain all openings in a closed position at all times when not in use: tank with capacity less than 19,813 gallons, tank with capacity less than 39,890 gallons that has daily average throughput not greater than 480 gallons.

Any gasoline storage tank with capacity greater than or equal to 19,813 gallons that does not meet any of the criteria specified above be equipped with the following: a closed vent system and control device achieving at least 95 weight-percent HAP/TOC reduction; equip with internal floating roof according to the requirements in 40 CFR Part 60 Subpart Kb; equip with external floating roof according to the requirements in 40 CFR Part 60 Subpart Kb. NESHAP 40 CFR 63 Subpart BBBBBB also requires monthly leak inspection of all equipment in gasoline service. The source testing, monitoring, and reporting requirements of this NESHAP are very similar to 40 CFR Part 60 Subpart Kb.

The District evaluated the requirements of the NESHAPs and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4623.

Rule 4624 (Transfer of Organic Liquid)

1. EPA Control Techniques Guidelines (CTG)

- EPA-450/2-77-026 1977/10 (Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals)

This CTG applies to facilities with a throughput of more than 20,000 gallons per day. This CTG states that the recommended loading terminal emission limit that can be achieved through the application of RACT is 0.64 lb VOC per 1,000 gallons of gasoline loaded. The District evaluated the requirements of the CTG and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4624.

2. Alternative Control Techniques (ACT)

- EPA 1992 ACT Document for Control Techniques for VOC Emissions from Stationary Sources (EPA-453/R-92-018 1992/12)

This document outlines the various control techniques and emission reductions that would occur at a variety of facilities, including organic liquid transfer operations. The control techniques are similar to the requirements for Rule 4624 including vapor control system requirement. The District evaluated the requirements of the ACT and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4624.

3. Federal New Source Performance Standards (NSPS)

- 40 CFR 60 Subpart XX - Standards of Performance for Bulk Gasoline Terminals (2003/12)

As NSPS requirements only apply to new/modified/reconstructed equipment they are more stringent than RACT which applies as a retrofit requirement to existing equipment. Therefore, the requirements of the subject NSPS exceed the requirements of RACT.

4. National Emission Standards for Hazardous Air Pollutants (NESHAPs) and Maximum Achievable Control Technologies (MACTs)

- 40 CFR 63 Subpart EEEE - Organic Liquids Distribution (Non-Gasoline) (2006/07)
- 40 CFR 63 Subpart BBBBBB - Gasoline Distribution Facilities (Bulk Gasoline Terminal and Pipeline Breakout Station (2011/01)

NESHAP 40 CFR 63 Subpart EEEE requires emissions from storage tank with capacity greater than 5,000 gallons be routed through a closed vent system into any combination of control devices achieving at least 95 weight-percent HAP reduction, or a reduction to an exhaust concentration less than or equal to 20 ppmv (control devices must meet applicable testing, monitoring and operating standards depending on type of device).

NESHAP 40 CFR 63 Subpart BBBBBB applies to gasoline storage tanks, gasoline loading racks, vapor collection-equipped gasoline cargo tanks, and the equipment components in vapor or liquid gasoline service

For bulk gasoline terminal with a throughput equal to or more than 250,000 gallons per day, this NESHAP requires the use of a vapor collection system with VOC emissions to the atmosphere not exceeding 0.67 lb/1,000 gallons (80 milligrams/liter). The vapor collection system shall be designed to prevent vapors collected at one loading rack or lane from passing to another loading rack or lane, and only vapor-tight gasoline tank trucks shall be loaded. The operator shall obtain the vapor tightness documentation for trucks to be loaded. Tank numbers are to be recorded during loading and subsequently cross-checked with filed vapor tightness documentation. If the cross-checking reveals that a non-vapor tight tank was loaded, the operator must notify the tank owner and ensure that the tank is not reloaded at that facility until vapor tightness documentation is obtained.

For bulk gasoline terminal with a throughput less than 250,000 gallons per day, this NESHAP requires the use of submerged filling method with a submerged fill pipe that is no more than 6 inches from the bottom of the cargo tank. Gasoline throughput records must be available within 24 hours of a request by the administrator.

The District evaluated the requirements of the NESHAP and determined that there are no conflicts or inconsistencies with the proposed requirements of Rule 4624.

III. CONCLUSION

Based on the above analysis, District staff concludes that the proposed amendments to the LDAR Rules would not conflict with any District or federal rules, regulations, or policies covering similar stationary sources.

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APPENDIX F

Best Available Retrofit Control Technology (BARCT) and Reasonably Available Control Technology (RACT) Analysis for Proposed Amendments to Rules 4401, 4409, 4455, 4623 and 4624

June 15, 2023

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BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY AND REASONABLY AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR PROPOSED RULES 4401, 4409, 4455, 4623, and 4624

I. BACKGROUND

A. Best Available Retrofit Control Technology

Most existing stationary sources in California non-attainment areas, such as the San Joaquin Valley, have been subject to Best Available Retrofit Control Technology (BARCT) requirements since the 1980s. California Health and Safety Code (CH&SC) Section 40406 defines BARCT as follows:

Best Available Retrofit Control Technology (BARCT) is an air emission limit that applies to existing sources and is the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts by each class or category of source.

In September of 2017, the California State Legislature and Governor passed Assembly Bill 617 (AB 617)[1], Non-vehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants. One requirement of AB 617 is for California air districts located in non-attainment areas to perform a Best Available Retrofit Control Technology (BARCT) analysis of their existing rules and regulations, and if applicable, propose an expedited schedule for revising rules that are found to not meet BARCT requirements by no later than December 31, 2023. AB 617 requires the expedited BARCT implementation schedule to apply to each industrial source that, as of January 1, 2017, was subject to the Cap-and-Trade program and gives the highest priority to those permitted units that have not modified emissions-related permit conditions for the greatest period of time. AB 617 also recognizes that "Existing law also authorizes a district to establish its own best available retrofit control technology requirement based upon the consideration of specified factors."

B. Reasonably Available Control Technology

Sections 182(b)(2) and 182(f) of the federal Clean Air Act require ozone nonattainment areas to implement Reasonably Available Control Technology (RACT) for sources that are subject to Control Techniques Guidelines (CTG) documents issued by the U.S. Environmental Protection Agency (EPA) and for "major sources" of volatile organic compounds (VOCs) and nitrogen oxide (NOx), which are ozone precursors. RACT can be defined as devices, systems, process modifications, or other apparatus or techniques that are reasonably available, taking into account the necessity of imposing such controls in order to attain and maintain a national ambient air quality standard (NAAQS); the social, environmental, and economic impact of such controls; and

[1] AB 617, Garcia, C., Chapter 136, Statutes of 2017.

alternative means of providing for attainment and maintenance of such a standard. These control techniques, which are defined in EPA guidelines for limiting emissions from existing sources in nonattainment areas, are adopted and implemented for nonattainment areas by state analysis.

On September 30, 2022, EPA finalized in the Federal Register a limited approval, limited disapproval of the California's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities[2] also known as the California Oil and Gas Regulation (COGR)[3]. The Technical Support Document (TSD)[4] from this action references the 2016 CTG as containing EPA's RACT recommendations for reducing VOC emissions from special equipment and processes used in the oil and natural gas industry. As part of this action, EPA cited deficiencies in COGR and a number of local California air district rules (the District, South Coast AQMD, Sacramento Metropolitan AQMD, Ventura County APCD, Yolo-Solano APCD, and Feather River AQMD). For the District, EPA identified Rules 4401 and 4623 as deficient in meeting RACT requirements as outlined in the 2016 CTG. As such, this rulemaking action also addresses the deficiencies identified by EPA.

II. Best Available Retrofit Control Technology (BARCT) Analysis

Based on the District's recent AB 617 BARCT analysis, the District evaluated potential amendments to the leak detection and repair requirements for District Rules 4401, 4409, 4455, 4623, and 4624. As part of this analysis, the District reviewed leak thresholds and repair timeframes from the following air district rules, and state and federal regulations and guidelines:

- Bay Area Air Quality Management District (BAAQMD)
- California Oil and Gas Regulation (COGR)
- Santa Barbara County Air Pollution Control District (SBCAPCD)
- South Coast Air Quality Management District (SCAQMD)
- Ventura County Air Pollution Control District (VCAPCD)
- EPA 2016 Control Technology Guideline for the Oil and Gas Industry (EPA-453/B-16-001)
- EPA New Source Performance Standards (NSPS)

[2] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, October 2018, https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf

[3] EPA. *Limited Approval, Limited Disapproval, of California Air Plan Revisions; California Air Resources Board, Final Rule*. (30 September, 2022) Retrieved from: https://www.govinfo.gov/content/pkg/FR-2022-09-30/pdf/2022-20870.pdf

[4] EPA. *Technical Support Document for EPA's Rulemaking for the California State Implementation Plan.* April 2022. Retrieved from: https://www.regulations.gov/document/EPA-R09-OAR-2022-0416-0002

The District completed an in-depth review of local, state, and federal regulations, and found that the current VOC control technology requirements in Rules 4401, 4623, and 4624 meet or exceed BARCT levels of control; therefore, the District is proposing no changes to the VOC control requirements within these rules. Rules 4409 and 4455 only include LDAR requirements; however, facilities subject to these rules may have equipment subject to the control requirements of other District Rules, such as Rule 2201 (New and Modified Stationary Source Review), Rule 4311 (Flares), Rule 4623, and Rule 4624.

The proposed amendments to the rules are as stringent as or more stringent than analogous rules that apply to similar sources in other California air districts, including LDAR requirements that have recently and previously been determined to satisfy BARCT. The 500 ppmv VOC leak limit for components subject to the rules included in the proposed amendments will reduce VOC emissions emitted from sources in the crude oil and natural gas sector. The District has determined that the new requirements included in the proposed amendments to the rules meet or exceed BARCT requirements.

III. Reasonably Available Control Technology (RACT) Analysis

On September 30, 2022, EPA finalized in the Federal Register a limited approval, limited disapproval of COGR. The TSD from this action references the 2016 CTG as containing EPA's RACT recommendations for reducing VOC emissions from special equipment and processes used in the oil and natural gas industry. As part of this action, EPA cited deficiencies in COGR and local air district rules, including District Rules 4401, and 4623. EPA's limited disapproval addressed the following deficiencies in District Rule 4401 and 4623:

1. Current rules (4401 and 4409) have a minor leak threshold of 2,000 ppmv for Rule 4401 and 1,000 ppmv for Rule 4409, while the 2016 CTG recommends 500 ppmv.
2. Current rule (4401) requires annual inspections while CTG recommends more frequent monitoring.
3. Current rules (4401 and 4409) exempt one-half inch and smaller stainless steel tube fittings used to supply natural gas to equipment or instrumentation from continuous monitoring, while the CTG does not provide for this exemption.
4. Unclear whether current rule (4623) requires vapor control systems for storage tanks with Potential to Emit (PTE) greater than 6 tons per year of VOC or actual emissions greater than or equal to 4 tons per year.

Addressing EPA's TSD for Rule 4401

For components at well sites, the 2016 CTG recommends conducting monthly inspections of valves and pumps using EPA Reference Method 21 at a 500 ppmv leak

threshold until the components are leak free for two consecutive months, then inspections can transition to quarterly inspections at 500 ppmv. For all other components, inspections must be conducted semi-annually. The 2016 CTG suggests that monthly inspections at 500 ppmv achieve an emission reduction of 92 percent, while semi-annual inspection for all other components achieve an emission reduction of 74 percent. In 2018, CARB staff determined in their Staff Report[5] the overall emission reduction for monthly inspection of valves and semi-annual inspection of all other components achieves 80 percent reduction, using a weighted average of the monthly and annual inspection based on the distribution of valves and connectors included in the 2016 CTG's model natural gas processing plant.[6]

The District is proposing quarterly inspections using EPA Reference Method 21 at 500 ppmv for all components subject to Rule 4401. Emission reductions from EPA Reference Method 21 monitoring programs are estimated for a variety of monitoring frequencies and leak thresholds using the EPA Protocol for Equipment Leak Emission Estimates[7], consistent with the 2016 CTG. Using this protocol, quarterly monitoring at a leak threshold of 500 ppmv achieves 89 percent emission reductions overall. By contrast, the 2016 CTG as noted achieves 80 percent reductions with its combination of monthly and semi-annual inspections at 500 ppmv as recommended for components located at well sites.

The District's proposal of quarterly inspection of all components at 500 ppmv provides greater emission reduction than the monthly monitoring of valves and pumps. Following the EPA protocol, increasing the frequency of monitoring to quarterly for all components results in greater emission reductions compared to increasing the monitoring frequency for certain components. Therefore, the District is proposing quarterly monitoring at 500 ppmv for all components.

[5] CARB. *Staff Report: Proposed Submission of California's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities Into the California State Implementation Plan.* (September 21, 2018). Retrieved from: https://ww2.arb.ca.gov/sites/default/files/2020-04/O_G%20CTG%20-%20Staff%20Report.pdf

[6] EPA. *Control Techniques Guidelines for the Oil and Natural Gas Industry*. (2016). Retrieved from: https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf

[7] EPA. *Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)*. Research Triangle Park, NC: Office of Air Quality Planning and Standards. (1995). Retrieved from: https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

Addressing EPA's TSD for Rule 4623

Current District Rule 4623 requires vapor control systems based on size of tank and TVP of the stored liquid. EPA's CTG requires a vapor control system based on if the PTE of storage tank equals or exceeds six (6) tons per year or if the actual VOC emissions exceed four (4) tons per year. The District believes that based on the current requirements of Rule 4623, all tanks that have a PTE greater than 6 tons per year or actual emissions greater than 4 tons per year more than likely already have installed vapor control systems. However, to ensure that there is no deficiency in meeting the CTG requirements, the District is proposing to add the following language to District Rule 4623 in the applicability and tank requirements sections:

> Section 2.0 Applicability
> *This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held, or stored, and any tank used in crude oil or natural gas production operations with a potential to emit six (6) tons of VOC or greater per year.*
>
> Section 5.0 Requirements
> *If a tank has the Potential to Emit greater than or equal to six (6) tons per year of VOC and actual emissions are greater than or equal to four (4) tons per year using a generally accepted model or calculation methodology, operator must install a vapor control system meeting the specifications described in Sections 5.3, 5.4, 5.5 or 5.6.*

Addressing EPA's Comments for Rule 4409

Although not initially cited in the TSD, EPA provided comments to the District during the rulemaking stating that the CTG is more stringent for equipment at natural gas processing facilities. The 2016 CTG recommends conducting monthly inspections of valves and pumps using EPA Reference Method 21 at a 500 ppmv leak threshold until the components are leak free for two consecutive months, then inspections can transition to quarterly inspections at 500 ppmv. For all other components at natural gas processing plants, inspections must be conducted annually. The 2016 CTG states that monthly inspections at 500 ppmv achieve an emission reduction of 92 percent, while annual inspection for all other components achieve an emission reduction of 68 percent.[8] In 2018, CARB staff determined that the monthly inspection of valves and annual inspections of all other components achieves a 74 percent reduction in emissions, using a weighted average of the monthly and annual inspection based on the distribution of valves and connectors included in the 2016 CTG's model natural gas processing plant.[8]

The District is proposing quarterly inspections using EPA Reference Method 21 at 500 ppmv for all components subject to Rule 4409. Emission reductions from EPA

[8] EPA. *Control Techniques Guidelines for the Oil and Natural Gas Industry*. (2016). Retrieved from: https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf

Reference Method 21 monitoring programs are estimated for a variety of monitoring frequencies and leak thresholds using the EPA Protocol for Equipment Leak Emission Estimates[9], consistent with the 2016 CTG. Using this protocol, quarterly monitoring at a leak threshold of 500 ppmv achieves 89 percent emission reductions overall. By contrast, the 2016 CTG as noted achieves 74 percent reductions with its combination of monthly and annual inspections at 500 ppmv as recommended for components located at natural gas processing facilities.

The District's proposal of quarterly inspection of all components at 500 ppmv outweighs the impact of monthly monitoring of valves and pumps. Using the EPA protocol, increasing the frequency of monitoring to quarterly for all components at 500 ppmv results in higher emission reductions than increasing the monitoring frequency for certain components. Therefore, the District is proposing quarterly monitoring at 500 ppmv for all components.

In their final ruling published in the Federal Register[4], EPA also commented on the potential deficiency for heavy crude oil with an API gravity of less than 20. The disapproval outlines the lack of analysis provided to EPA that demonstrate controls are not cost effective, or that emissions are minimal, which would satisfy RACT requirements. CARB has conducted and submitted to EPA an analysis demonstrating that no deficiency exists in their 2023 Initial Statement of Reasoning.[10] The analysis included the approximate cost to eliminate their heavy oil exemption. In the analysis, CARB projects an increased cost of $26,023,588 per year. The emission reductions are projected at 299.8 metric tons per year of methane, which is equivalent to 0.148 tons of VOC per day.[11] CARB's analysis found that the emissions from heavy oil components are insignificant, and therefore no further District action is needed.

A. RACT Analysis Conclusion

The requirements included in the proposed amendments to Rule 4401, 4409, and 4623 are more stringent than the 2016 CTG recommendations. The 500 ppmv minor leak threshold for components subject to the rules included in the proposed amendments will significantly reduce the VOC emissions emitted from sources in the crude oil and natural gas sector. The District has determined that the new requirements included in the proposed amendments to the rules meet or exceed RACT recommendations.

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[9] EPA. *Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)*. Research Triangle Park, NC: Office of Air Quality Planning and Standards. (1995). Retrieved from: https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

[10] California Air Resources Board. Public Hearing to Consider the Proposed Amendments to the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2023/oilgas2023/isr.pdf

[11] California Air Resources Board. Appendix B: Economic Analysis for Proposed Amendments to the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2023/oilgas2023/israppb.pdf

IV. Conclusion

Based on the evaluation of other applicable rules for this source category, and the evaluations for rules subject to the 2016 CTG, the District concludes that the proposed rule amendments fulfill or exceed BARCT and RACT requirements.

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Exhibit 12

Potential to Emit Calculations

Potential to Emit (PE) Calculations

The PE for each component type is the sum of the emissions from the three ranges:

$PE_{component\ type}$ (lb/day) = Range 1 emissions + Range 2 emissions + Range 3 emissions

Range emissions (lb/day) = emission factor (kg/hr) × number of components × percentage in range × 2.2046 lb/kg × 24 hr/day

Example for valves:

Range 1 emissions = 7.8E-06 × 251 × 90% × 2.2046 × 24 = 0.093229 lb/day

Range 2 emissions = 0.00007080 × 251 × 9.5% × 2.2046 × 24 = 0.089323 lb/day

Range 3 emissions = 0.00220797 × 251 × 0.5% × 2.2046 × 24 = 0.146615 lb/day

PE_{valves} = 0.093229 + 0.089323 + 0.146615 = 0.33 lb/day (rounded)

The same calculation for each component type (880 components) gives a total PE of 1.3 lb-VOC/day (483 lb-VOC/year), as shown below and in Appendix C of the Engineering Evaluation.

Equipment Type	Service	Component Count	% Default Zeros	%Pegged (>9,999)	% in Correlation Range	Correlation Screening Value (ppm)	Default Zero Emissions (lb/day)	Pegged Emissions (lb/day)	Correlation Emissions (lb/day)	VOC emissions (lb/day)
Valves	All	251	90.0%	0.5%	9.5%	100	0.093229	0.146615	0.089323	0.33
Pump Seals	All	6	90.0%	0.5%	9.5%	500	0.005429	0.024754	0.072977	0.10
Others	All	36	90.0%	0.5%	9.5%	500	0.006857	0.030606	0.084982	0.12
Connectors	All	120	90.0%	0.5%	9.5%	100	0.042857	0.042693	0.027361	0.11
Flanges	All	467	90.0%	0.5%	9.5%	100	0.006894	0.373160	0.274587	0.65
Open-ended lines	All	0	90.0%	0.5%	9.5%	500	0.000000	0.000000	0.000000	0.00

Total VOC Emissions (lb/day) = 1.3
Total VOC Emissions (lb/yr) = 483

Exhibit 13

BACT CE Analysis

Cost Effectiveness Analysis For Leak Threshold of 100 ppm For Pump and Compressor Seals

The District's VOC cost-effectiveness threshold is $27,500 per ton of emissions reduced. If a more stringent, feasible, control option costs less to implement than $27,500 per ton, then the control option is cost effective and must be employed.

To determine if the lower leak threshold of 100 ppm is cost-effective as an alternative to 500 ppm, we must determine how many tons of VOC emissions would be reduced by employing that option.

Calculating Emission Reduction:

The Potential to Emit was calculated by using the CAPCOA Correlation Equation (Method 3). The VOC emissions reduction is determined by calculating the emissions at both concentration levels for each component type, pump seals and compressor seals. Note that compressor seals are not their own category, like pump seals, but are part of the Others Category. There are 6 pump seals and 6 compressor seals.

For **pump seals**, the Correlation Equation is (SV of 500 and 100):

- # of components × leak percent × 5.07E-05$(SV)^{0.622}$ × 2.2046 × 24 hrs/day × 365 ÷ 2,000 lbs/ton

At 500 ppm: 6 × 9.5% × 0.0024197 × 2.2046 × 24 hrs/day = 0.013 tons/year

At 100 ppm: 6 × 9.5% × 0.0008892 × 2.2046 × 24 hrs/day = 0.005 tons/year

For **others**, the Correlation Equation is (SV of 500 and 100):

- # of components × leak percent × 8.69E-06$(SV)^{0.642}$ × 2.2046 × 24 hrs/day × 365 ÷ 2,000 lbs/ton

At 500 ppm: 6 × 9.5% × 0.0004696 × 2.2046 × 24 hrs/day = 0.003 tons/year

At 100 ppm: 6 × 9.5% × 0.0001671 × 2.2046 × 24 hrs/day = 0.0009 tons/year

	At 500 ppmv	**At 100 ppmv**	**Difference**
Pump seal	0.013 tons/year	0.005 tons/year	0.010 tons/year
Other	0.003 tons/year	0.0009 tons/year	0.002 tons/year

The total VOC emissions reductions are 0.010 + 0.002 = 0.012 tons/year

Determine Cost of Emissions Reductions

All 12 components: 0.012 tons/year × $27,500 per ton = $330/year

To be cost-effective, the incremental cost of this emissions reduction cannot exceed **$330**.

Pumps, and their associated components, have been identified as components that cannot be easily repaired, but rather requirement replacement. The average labor rate is $133/hr. The replacement time for a seal is 40 hours. A pump or compressor seal costs $166.10. (Final Draft Staff Report, Appendix C, p. C-8, Table C-4.) Repair for one seal would cost:

$133 × 40 + $166.10 = $5486.10

Determine Cost Effectiveness

The District uses a 10-year average to determine cost effectiveness. The cost to repair one seal averaged over 10 years is $548.61, which is greater than the threshold of $330. Therefore, the control option of a leak threshold of 100 ppm for pump seals and compressors is **not cost effective**. Therefore, this option would not be considered further.

Exhibit 14

District Emission Factor Calculations

District Emission Factor Inputs by Component Type and Range

(Table IV-3a equations)

Component Type	Range 1: Default Zero Factor (kg/hr)	Range 2: Correlation Equation (kg/hr)	Range 3: Pegged Correlation Equation at 9,999 ppmv (kg/hr)
Valves	7.8E-06	$2.27E\text{-}06(100)^{0.747}$	$2.27E\text{-}06(9{,}999)^{0.747}$
Pump Seals	1.9E-05	$5.07E\text{-}05(500)^{0.622}$	$5.07E\text{-}05(9{,}999)^{0.622}$
Others	4.0E-06	$8.69E\text{-}06(500)^{0.642}$	$8.69E\text{-}06(9{,}999)^{0.642}$
Connectors	7.5E-06	$1.53E\text{-}06(100)^{0.736}$	$1.53E\text{-}06(9{,}999)^{0.736}$
Flanges	3.1E-07	$4.53E\text{-}06(100)^{0.706}$	$4.53E\text{-}06(9{,}999)^{0.706}$

Emission Factor Calculations

Step 1: Determine the Range 2 (Correlation Equation) and Range 3 (Pegged Correlation Equation) emission factors from the equations. Example (valves):

Range 2 valves emission factor (kg/hr) = $2.27E\text{-}06 \times 100^{0.747} = 0.00007080$ kg/hr

Range 3 valves emission factor (kg/hr) = $2.27E\text{-}06 \times 9{,}999^{0.747} = 0.00220797$ kg/hr

District Final Emission Factors (kg/hr per component)

Component Type	Range 1: Default Zero Emission Factor	Range 2: Correlation Equation Emission Factor	Range 3: Pegged Correlation Equation Emission Factor (9,999 ppmv)
Valves	0.00000780	0.00007080	0.00220797
Pump Seals	0.00001900	0.00241973	0.01559484
Others	0.00000400	0.00046963	0.00321360
Connectors	0.00000750	0.00004536	0.00134481
Flanges	0.00000031	0.00011698	0.00302042

Exhibit 15

Kern Energy I&M

Rule 4455 Inventory (as of end of 2023)	Total Components
COMPRESSOR	63
DRAIN	278
FLANGED CONNECTION	13,083
Other	1,656
PRESSURE RELIEF DEVICE	262
PUMP	220
THREADED CONNECTOR	52,168
VALVE	13,153
Total	**80,883**

2022			
Component Type	**"Default Zero"**	**"In Range"**	**"Pegged"**
COMPRESSOR	58	4	1
DRAIN	257	16	5
FLANGED CONNECTION	13,039	33	11
OTHER	1,578	49	29
PRESSURE RELIEF DEVICE	244	13	5
PUMP	191	22	7
THREADED CONNECTOR	51,786	285	97
VALVE	13,049	82	22
Total	**80,202**	**504**	**177**
Percent of Inventory:	99.16%	0.62%	0.22%

2023			
Component Type	**"Default Zero"**	**"In Range"**	**"Pegged"**
COMPRESSOR	54	6	3
DRAIN	261	15	2
FLANGED CONNECTION	13,043	28	12
OTHER	1,578	50	28
PRESSURE RELIEF DEVICE	251	8	3
PUMP	188	28	4
THREADED CONNECTOR	51,812	261	95
VALVE	13,043	92	18
Total	**80,230**	**488**	**165**
Percent of Inventory:	99.19%	0.60%	0.20%

2024			
Component Type	**"Default Zero"**	**"In Range"**	**"Pegged"**
COMPRESSOR	51	7	5
DRAIN	269	5	4
FLANGED CONNECTION	13,066	13	4
OTHER	1,615	28	13
PRESSURE RELIEF DEVICE	254	7	1
PUMP	202	10	8
THREADED CONNECTOR	51,947	175	46
VALVE	13,084	66	3
Total	**80,488**	**311**	**84**
Percent of Inventory:	99.51%	0.38%	0.10%