San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

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DATE: June 15, 2023

TO: SJVUAPCD Governing Board

FROM: Samir Sheikh, Executive Director/APCO
Project Coordinator: Sheraz Gill

RE: <u>ITEM NUMBER 12: ADOPT PROPOSED AMENDMENTS TO DISTRICT LEAK DETECTION AND REPAIR RULES 4401, 4409, 4455, 4623, AND 4624</u>

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.

<u>DISCUSSION</u>:

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

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

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.

~~3.28~~9 ~~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.~~39~~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.~~39~~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.~~39~~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.~~39~~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.~~39~~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.~~49~~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~~3. 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.~~4~~5 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.

<u>6.3.3.1 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 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 <u>or no </u>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 <u>or Table 2</u>, 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.~~4~~5.

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.~~29~~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~~ <u>in violation</u> 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 ~~4~~7. Notify the APCO in writing prior to replacing or retrofitting the component; or

Table ~~4~~7 – 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^{o}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 <u>or Table 2</u>, Section~~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 ~~4~~6. Notify the APCO in writing prior to replacing or retrofitting the component; or

Table ~~4~~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~~s~~ 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.

<u>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.</u>

6.4.2 The VOC content shall be determined using American Society of Testing and Materials (ASTM) D 1945<u>-14</u> 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.~~24~~32.

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.~~4~~7 Contact Floating Roof: a roof, located inside an internal floating roof tank, that floats on the liquid surface.

3.~~5~~8 Crude Oil: petroleum extracted from the earth and which has not been processed in a refining operation.

3.~~6~~9 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.~~7~~10 Degassing: the process of removing organic vapors from a storage tank.

3.~~8~~11 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.~~9~~12 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.

3.1~~0~~3 Fixed Roof Tank: a tank with a roof that is permanently affixed to the shell of the tank.

3.1~~1~~4 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

3.1~~2~~5 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.

3.1~~3~~6 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.

3.1~~4~~7 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 <u>for pressure-vacuum</u> <u>relief</u> 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)~~ <u>California Geologic Energy Management Division (CalGEM)</u>.

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 ~~4~~6: 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^o up to 30^o 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^o 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:

$$\text{Corrected TVP} = \text{Calculated TVP} + C_F$$

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 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.

3.1~~4~~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.

3.2~~5~~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~~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 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.

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^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:

$$\text{Corrected TVP} = \text{Calculated TVP} + C_F$$

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 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

<u>ADOPT PROPOSED AMENDMENTS TO DISTRICT LEAK DETECTION AND REPAIR RULES 4401, 4409, 4455, 4623, AND 4624</u>

Attachment C:

<u>Final Draft Staff Report with Appendices for Proposed Amendments to Rules 4401, 4409, 4455, 4623, and 4624</u>

(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™

Table of Contents

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

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[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,

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[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

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[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 <u>or no</u> 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.

<u>Proposed Amendments to Rule 4455</u>

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

<table>
<tr><th colspan="6">Rule 4455 – Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants</th></tr>
<tr><th>Current Leak Standard</th><th>VCAPCD Rule 74.7</th><th>SBCAPCD Rule 331</th><th>BAAQMD Regulation 8 Rule 18</th><th>SCAQMD Rule 1173</th><th>EPA NSPS Subpart OOOO and OOOOa</th></tr>
<tr>
<td>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</td>
<td>Gas
• Minor: 1,000 ppmv
• Major: 10,000 ppmv

Liquid
• Minor: +3 drops min.
• Major: continuous flow</td>
<td>Gas
• Minor: 1,000 ppmv
• Major: 10,000 ppmv

Liquid
• Minor: +3 drops min.
• Major: continuous flow</td>
<td>Gas
• 100 ppmv (all other components except the ones with 500 ppmv)
• 500 ppmv (pumps, compressors, PRDs)</td>
<td>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.</td>
<td>• 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</td>
</tr>
</table>

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 <u>or no</u> 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.

<u>Proposed Amendments to Rule 4623</u>

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, <u>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.</u>

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) <u>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</u>.

- 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

<table>
<tr><th>Rules</th><th>% of Emissions Reduced at 500 ppmv</th><th>Tons/day of VOC reduced from CEPAM Data @ 500 ppmv</th></tr>
<tr><td>4401</td><td rowspan="2">19.9%</td><td rowspan="2">0.20</td></tr>
<tr><td>4409</td></tr>
<tr><td>4455</td><td>12.8%</td><td>0.02</td></tr>
<tr><td>4623</td><td>28.7%</td><td>0.69</td></tr>
<tr><td>4624</td><td>15.6%</td><td>0.18</td></tr>
<tr><td colspan="2">Total</td><td>1.09</td></tr>
</table>

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).

$$\%_{Reduced} = \frac{(\sum E_{Current} - \sum E_{Proposed})}{\sum E_{Current}} \qquad \text{(Equation 1)}$$

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:

$$ER = EI \times \%_{Reduced} \qquad \text{(Equation 2)}$$

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).

$$ALR = (LR * LkFrac) + ELTC \qquad \text{(Equation 3)}$$

Where,
ALR: Average Leak Rate in kilograms per hour
LR: Leak rate in kilograms per hour
LkFrac: Leak Fraction
ELTC: Equipment Leak Type Constant

$$EM = ALR * Components \qquad \text{(Equation 4)}$$

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.

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[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

June 15, 2023

Submitted to:

San Joaquin Valley Air Pollution Control District
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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%**

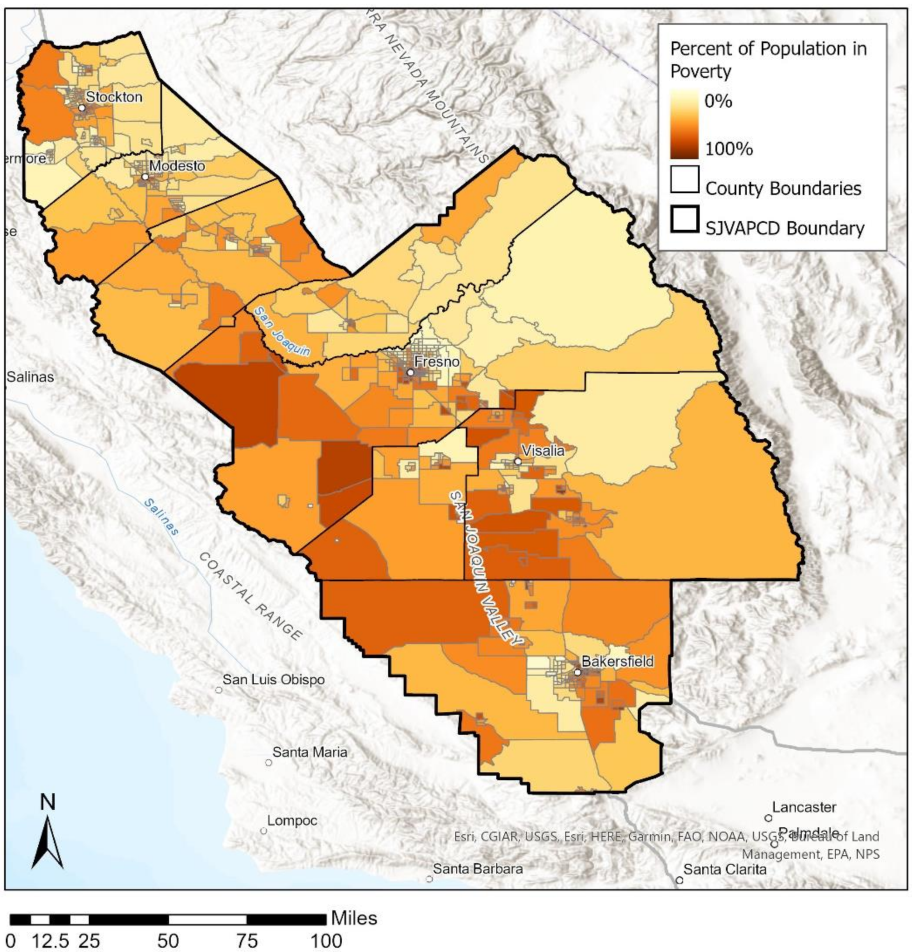
Source: U.S. Census Bureau, 2023c.

[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%**

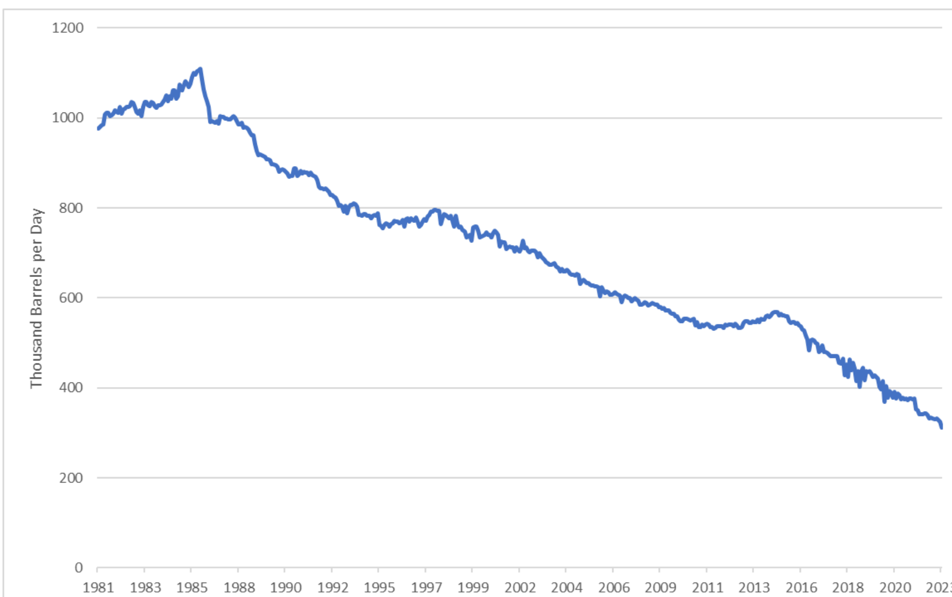
Source: BLS, 2022.

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.

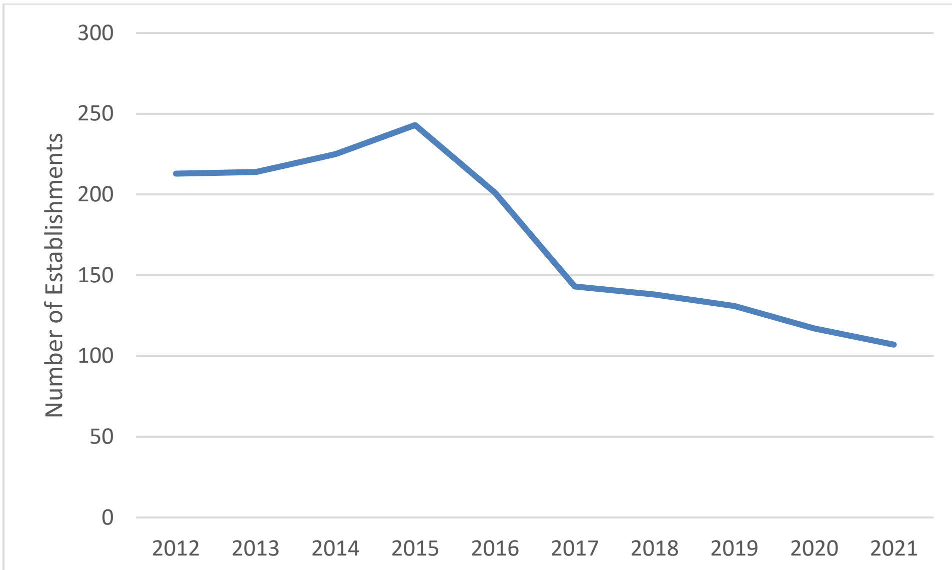
Figure 2. California Field Production of Crude Oil



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

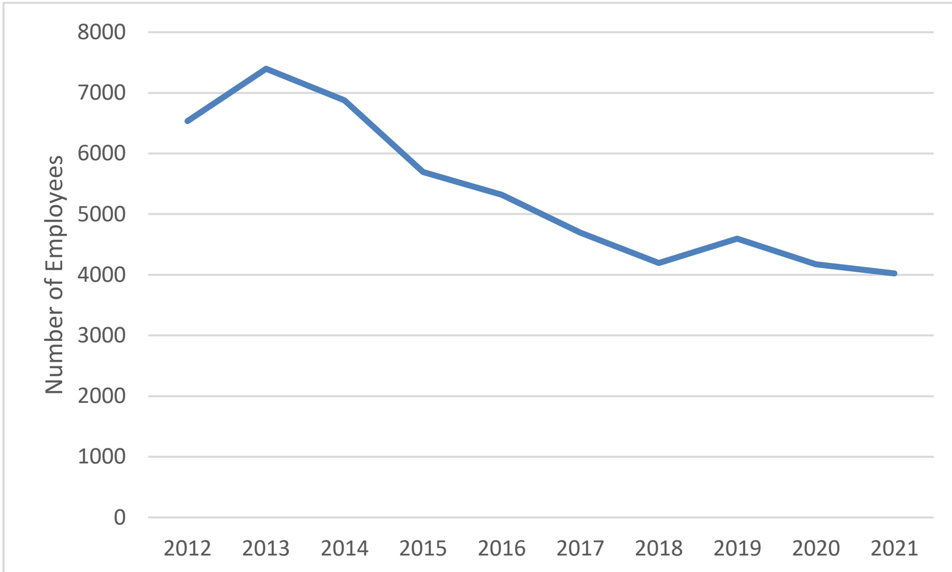


Source: U.S. Census Bureau, 2023e

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.

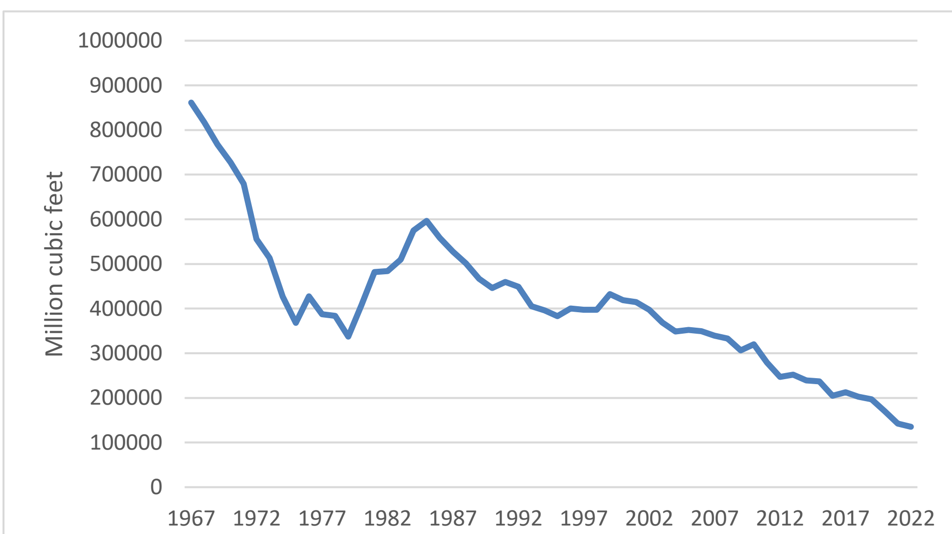
Figure 4. Employment in Crude Petroleum Extraction (NAICS 211120) in California



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.

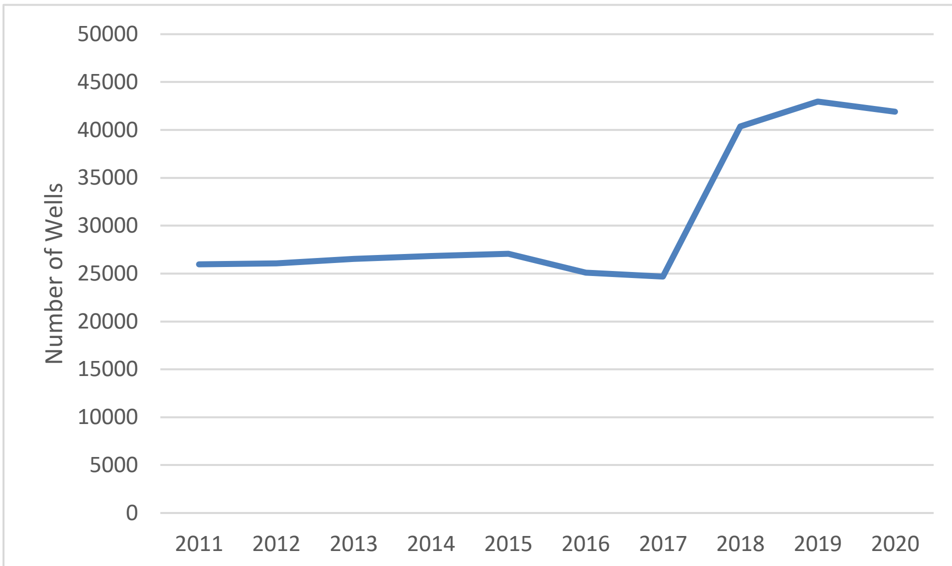
Figure 5. California Natural Gas Gross Withdrawals



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.

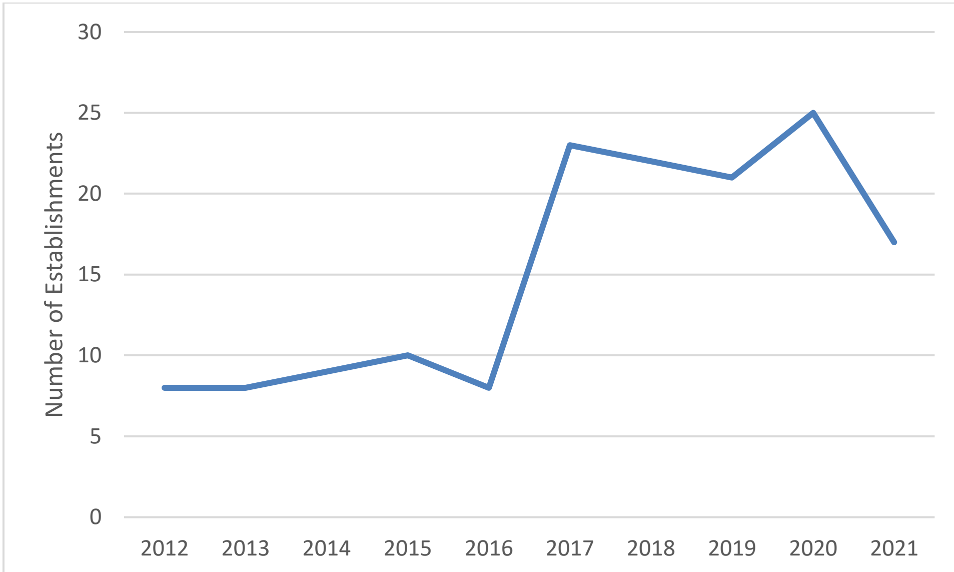
Figure 6. Number of Natural Gas Producing Wells in California



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.

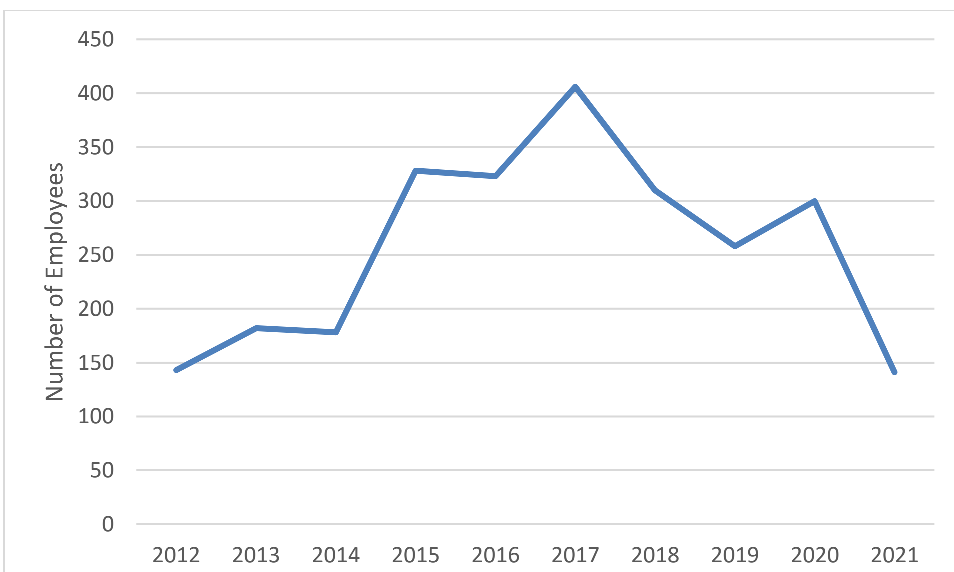
Figure 7. Establishments in Natural Gas Extraction (NAICS 211130) in California



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).

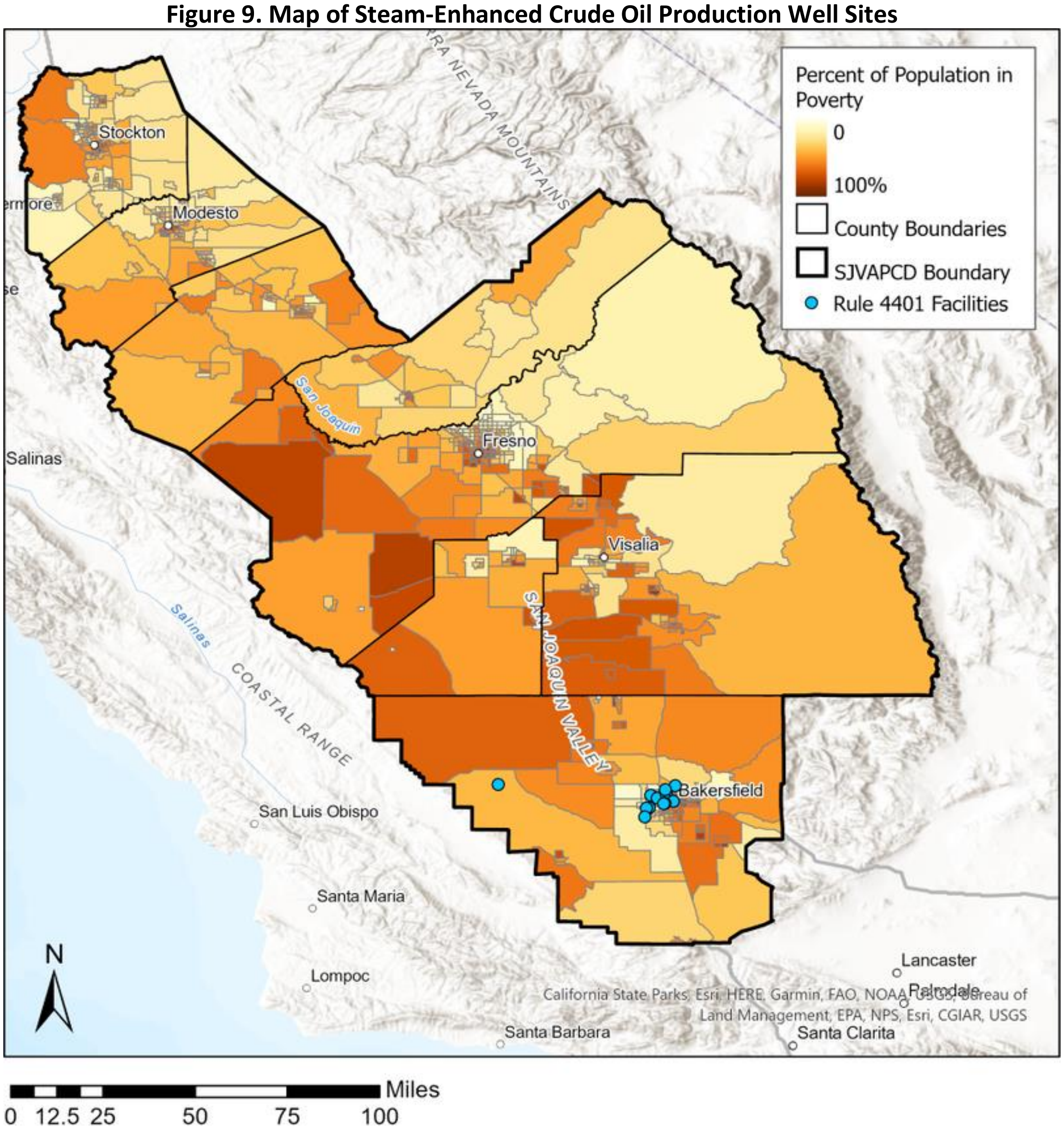
Based on the calculated costs, the IMPLAN model estimates how many jobs might be lost in reaction to the costs to affected companies. It also estimates indirect costs (i.e., the impact to affected firms' suppliers when the direct cost of rule compliance causes affected firms to reduce their purchases 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.

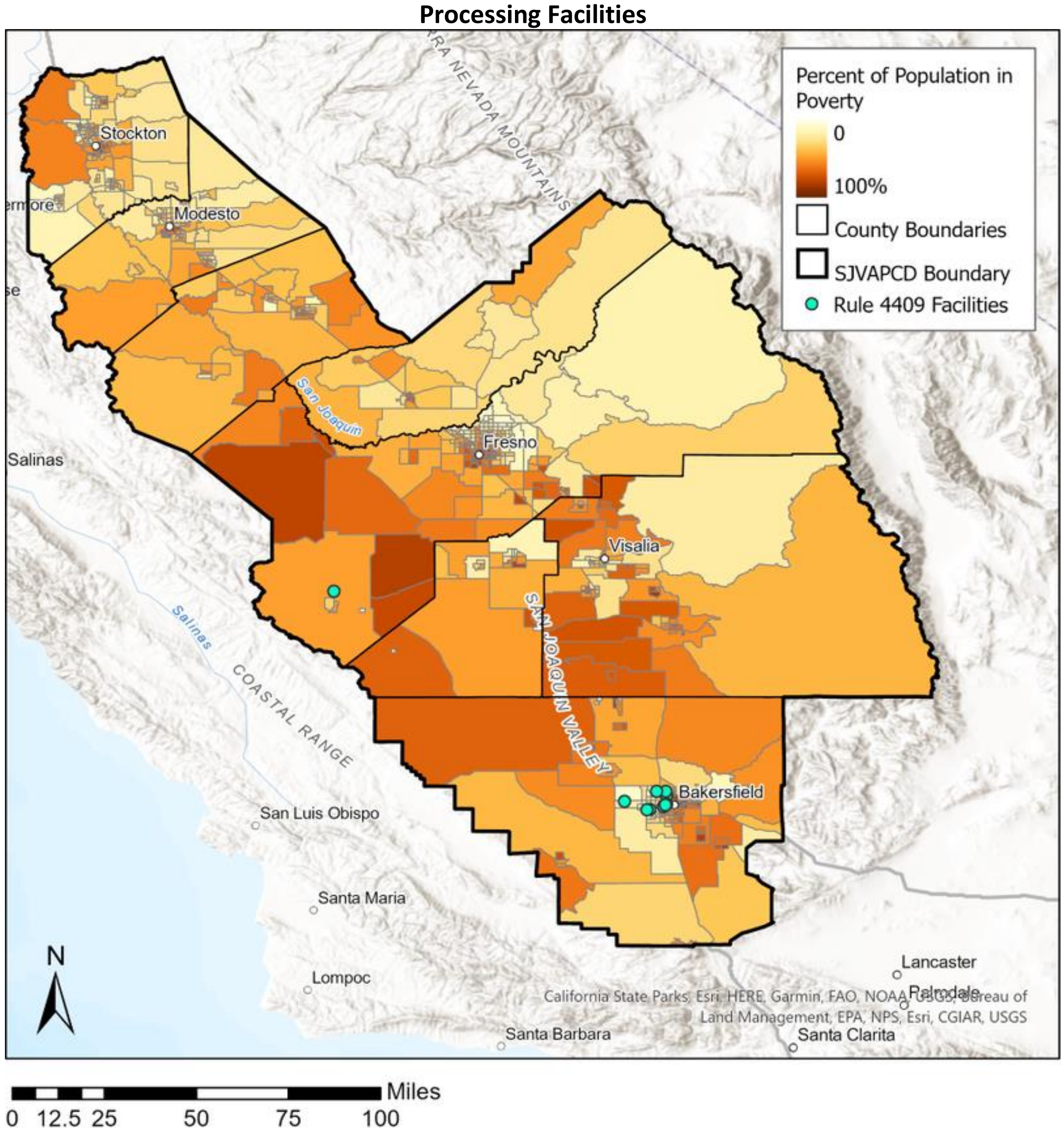
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

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%

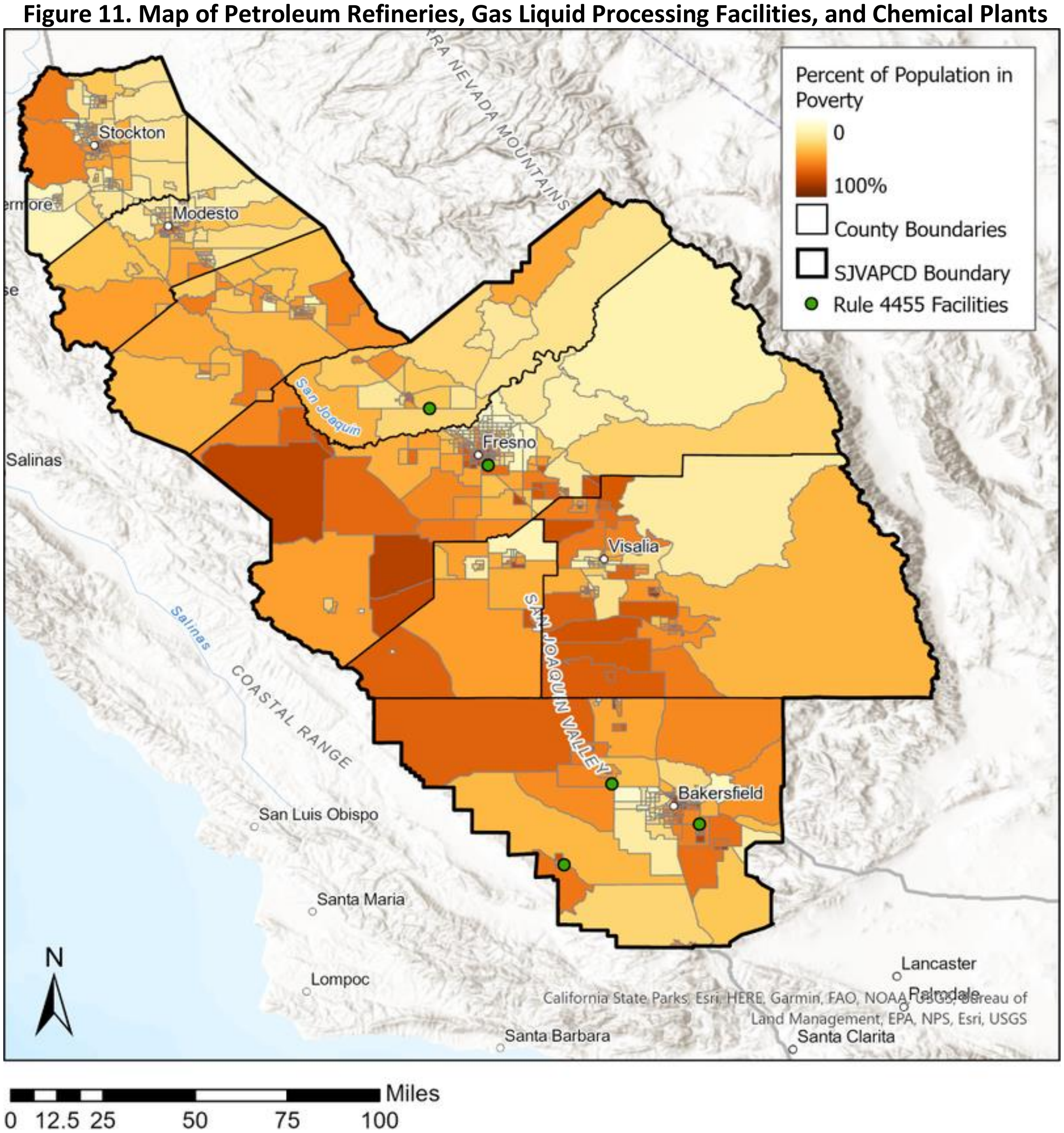
Source: ERG estimates based on IMPLAN, 2023.
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

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.

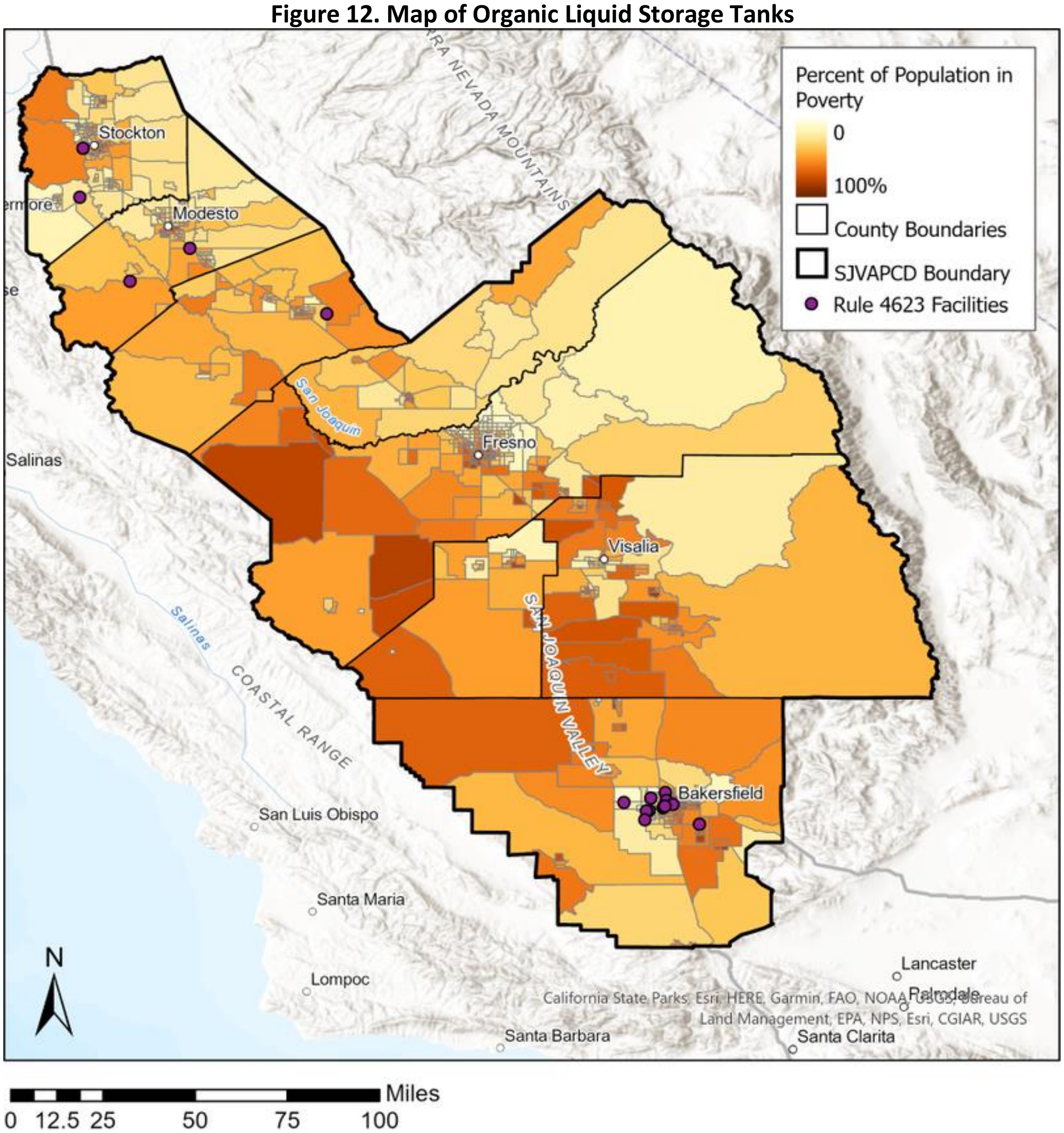
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

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.

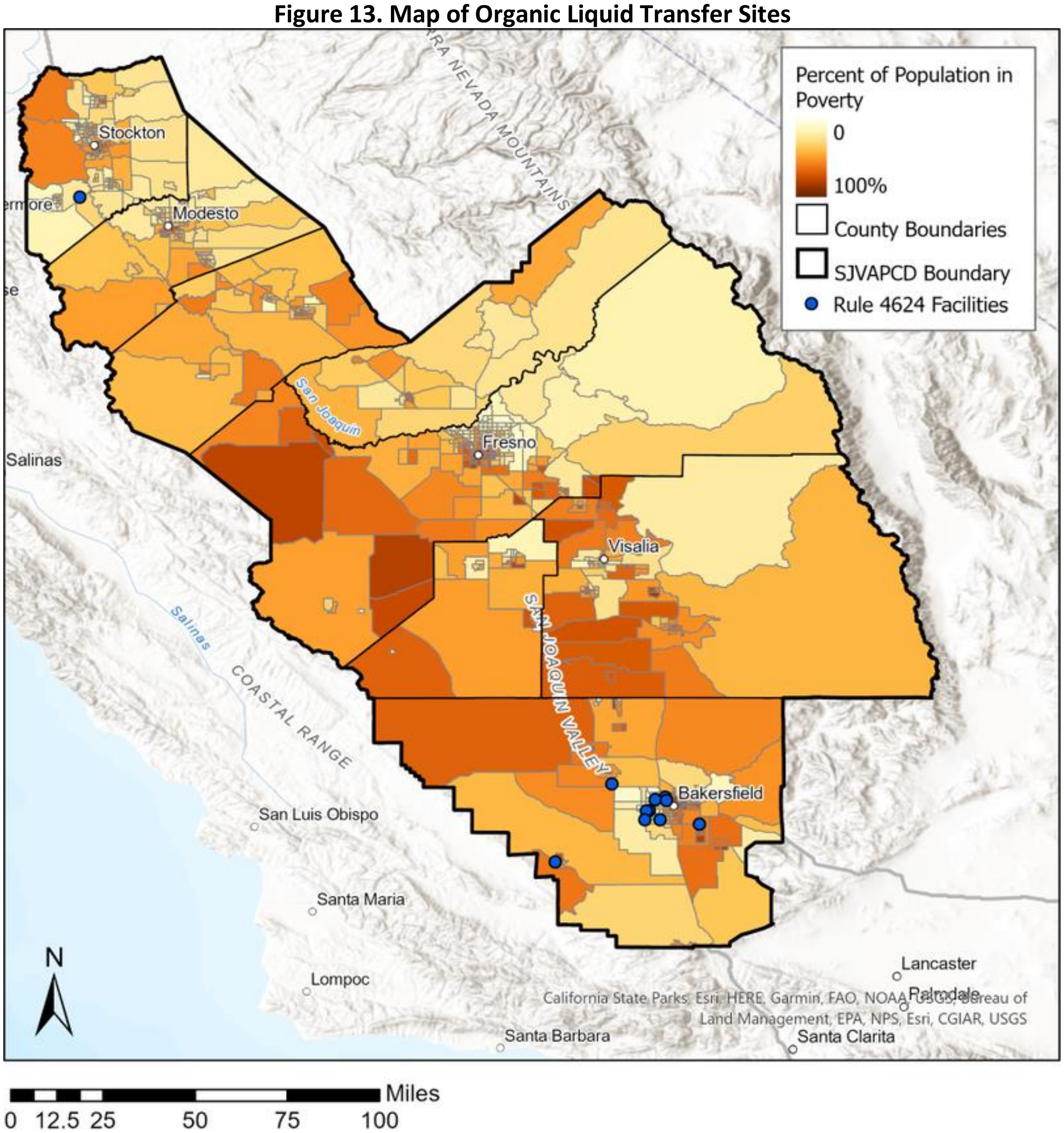
[a] While the SJVAPCD only includes a portion of Kern County, the data shown here include the whole of the county.

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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