BOARD MEETING DATE: August 2, 2024 AGENDA NO. 25

PROPOSAL: Determine That Proposed Amended Rule 1148.1 – Oil and Gas Production Wells, Is Exempt from CEQA; and Amend Rule 1148.1

SYNOPSIS: Rule 1148.1 – Oil and Gas Production Wells applies to facilities that operate oil and gas wells. Proposed Amended Rule 1148.1 (PAR 1148.1) will address objectives of the Community Emission Reduction Plan for the AB 617 community, Wilmington, Carson, and West Long Beach. PAR 1148.1 enhances leak detection provisions, establishes NOx limits for equipment that uses produced gas, and establishes requirements for workover rigs. PAR 1148.1 also bans the use of odorants, requires leak notifications, and updates signage requirements.

COMMITTEE: Stationary Source, May 17, 2024, Reviewed

RECOMMENDED ACTIONS:
Adopt the attached Resolution:

1. Determining that Proposed Amended Rule 1148.1 – Oil and Gas Production Wells, is exempt from the requirements of the California Environmental Quality Act; and
2. Amending Rule 1148.1 – Oil and Gas Production Wells.

Wayne Nastri
Executive Officer

SR:MK:MM

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**Background**

Rule 1148.1 was adopted on March 5, 2004, to reduce VOC emissions from wellheads and well cellars located at oil and gas production facilities. The rule requires increased inspection and maintenance, and control of produced gas emissions, with additional regulatory considerations when located within 100 meters of sensitive receptors.

Rule 1148.1 was amended on September 4, 2015, to provide enforceable mechanisms to reduce odor nuisance potential from emissions associated with oil and gas production facility operations. The 2015 amendment focused on the use of odor mitigation best practices; required facilities located within 1,500 feet of a sensitive receptor to conduct and submit a specific cause analysis for any confirmed odor event; and required facilities with continuing odor issues to develop and implement an approved Odor Mitigation Plan.

Two AB 617 communities, Wilmington, Carson, West Long Beach (WCWLB) and South Los Angeles (SLA), included objectives to address oil and gas well activities in their Community Emissions Reduction Plans (CERP). Proposed Amended Rule 1148.1 (PAR 1148.1) was developed to address CERP objectives related to increased monitoring of well activities, the use of lower emission or zero-emission equipment, and the elimination of odorants. PAR 1148.1 also addresses the 2022 Air Quality Management Plan Control Measure FUG-01: Improved Leak Detection and Repair by requiring enhanced monitoring of well sites.

**Public Process**
The development of PAR 1148.1 was conducted through a public process. Four Working Group Meetings were held on: April 20, 2023, September 14, 2023, December 14, 2023, and April 11, 2024. In addition, staff participated in AB 617 Community Steering Committee (CSC) Meetings to notify and update CSC members on the rule development process and progress on CERP objectives. Stakeholders include representatives from the community, environmental organizations, industry representatives, and government agencies. Staff also met individually with industry stakeholders and visited sites affected by the rule development process. A Public Workshop was held on February 1, 2024, where staff presented the proposed rule to the general public and stakeholders, and received comments related to the proposal.

**Proposal**
PAR 1148.1 will require the use of enhanced leak detection technology with Optical Gas Imaging (OGI) inspections monthly, establish NOx limits for equipment that uses produced gas, and source tests requirements. PAR 1148.1 will also require that workover rigs meet Tier 4 Final diesel engine standards, bans the use of odorants that are used to mask odors emanating from oil production sites, require submitting a notification for quantified leaks greater than 25,000 ppm VOC, adds new definitions to add clarity, updates signage requirements, and makes minor changes to rule language for consistency and clarity. Implementation of PAR 1148.1 is expected to result in emission reductions of 0.27 tons per day of VOC by 2025 and 0.51 tons per day of NOx by 2027.

**Key Issues**
Through the rulemaking process, staff has worked with stakeholders to address and resolve issues. Staff is not aware of any remaining key issues.

**California Environmental Quality Act**
Pursuant to the CEQA Guidelines sections 15002(k) and 15061, PAR 1148.1 is exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3). A Notice of Exemption has been prepared pursuant to CEQA Guidelines section 15062 and is included as Attachment H to this Board letter. If PAR 1148.1 is approved, the Notice of Exemption

will be filed for posting with the county clerks of Los Angeles, Orange, Riverside, and San Bernardino counties, and with the State Clearinghouse of the Governor's Office of Planning and Research.

**Socioeconomic Impact Assessment**

Approximately 323 facilities are subject to PAR 1148.1 with all belonging to the Oil and Gas Extraction (NAICS 211) sector. Out of the 323 facilities, up to 255 facilities may qualify as a small business based on various small business definitions. The key requirements of PAR 1148.1 that would have cost impacts for the affected facilities include: 1) conducting periodic OGI inspections; 2) purchasing and installing 3-way catalysts; 3) retrofitting workover rigs with Tier 4 Final engines; and 4) conducting periodic maintenance on equipment. The total present value of compliance costs of implementing PAR 1148.1 during the 2025-2046 period is estimated to be $92.0 million and $66.4 million at a 1% and 4% discount rate, respectively. The annual average compliance costs of PAR 1148.1 are estimated to range from $4.1 million to $4.7 million at a 1% to 4% real interest rate, respectively. When the compliance costs are amortized using a 4% real interest rate, 28 net jobs are forecasted to be foregone annually in the four-county region during the 2025-2046 period, relative to the baseline scenario. The impact of PAR 1148.1 on production costs and delivered prices in the South Coast AQMD region is expected to be minimal. The details of the Final Socioeconomic Impact Assessment can be found in Attachment I to this Board Letter.

**AQMP and Legal Mandates**

Under Health and Safety Code section 40460(a), the South Coast AQMD is required to adopt an AQMP demonstrating compliance with all federal regulations and standards. The South Coast AQMD is required to adopt rules and regulations that carry out the objectives of the AQMP. PAR 1148.1 addresses the 2022 Air Quality Management Plan Control Measure FUG-01: Improved Leak Detection and Repair by requiring monthly monitoring of well sites with the use of OGI technology.

**Implementation and Resource Impact**

Existing staff resources are adequate to implement the proposed amended rule.

**Attachments**

A. Summary of Proposal
B. Key Issues and Responses
C. Rule Development Process
D. Key Contacts List
E. Resolution
F. Proposed Amended Rule 1148.1
G. Final Staff Report
H. Notice of Exemption from CEQA
I. Final Socioeconomic Impact Assessment
J. Board Presentation

## ATTACHMENT A

## SUMMARY OF PROPOSAL

| Proposed Amended Rule 1148.1 – Oil and Gas Production Wells |
|---|
| *Applicability*<br>• Deleted the phrase “processed gas” and added the phrase “produced gas” for clarity and consistency<br><br>*Requirements*<br>• Updated signage requirements for specific installation locations and lettering size<br>• Maintain equipment free of visible vapors<br>• Establish emission limits for NOx of 11 ppmv at 15% oxygen for any engine that is powered by produced gas that is used to operate an oil producing or injection well<br>• Establish emission limits for NOx of 9 ppmv at 15% oxygen for any stationary gas turbine or fuel cell that is powered by produced gas<br>• Emissions from workover rig meet at least a Tier 4 Final standard<br>• Ban odorants and limit use of neutralizing agents to products that do not contain air toxics<br>• Notification for leaks greater than 25,000 ppm VOC<br><br>*Operator Inspection Requirements*<br>• Monthly Optical Gas Imaging inspections<br><br>*Testing Requirements*<br>• Source testing requirements and frequency for engines and microturbines<br><br>*Exemptions*<br>• Added exemption from source testing of microturbines that are certified by CARB’s Distributed Generation Certification Program |

**ATTACHMENT B**

**KEY ISSUE AND RESPONSE**

| Proposed Amended Rule 1148.1 – Oil and Gas Production Wells |
|---|
| Throughout the rulemaking process, staff worked with stakeholders to resolve key issues. Staff is not aware of any key remaining issues. |

# ATTACHMENT C

# RULE DEVELOPMENT PROCESS

Proposed Amended Rule 1148.1 – Oil and Gas Production Wells

Initiated Rule Development: February 2023

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Working Group Meetings (4): April 20, 2023, September 14, 2023, December 14, 2023, April 11, 2024

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75-Day Public Workshop Notice: January 19, 2024

↓

Public Workshop: February 1, 2024

↓

Stationary Source Committee Briefing: May 17, 2024

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Set Public Hearing: June 7, 2024

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30-Day Notice of Public Hearing: July 2, 2024

↓

Public Hearing: August 2, 2024

**Seventeen (17) months spent in rule development**

**Four (4) Working Group Meetings**

**One (1) Public Workshop**

**One (1) Stationary Source Committee Meeting**

# ATTACHMENT D

## KEY CONTACTS LIST

Proposed Amended Rule 1148.1 – OIL AND GAS PRODUCTION WELLS
(*listed alphabetically*)

- Bridge Energy
- California Geologic Energy Management Division
- California Resources Corporation
- Center for Biological Diversity
- Communities for a Better Environment
- City of Los Angeles Planning Department
- E&B Natural Resources
- Esperanza Community Housing Corporation
- FracTracker Alliance
- Pacific Coast Energy Company, LP
- Redeemer Community Partnership
- Signal Hill Petroleum
- STAND-LA
- Warren Resources
- WG Holdings

**ATTACHMENT E**

**RESOLUTION NO. 24-____**

**A Resolution of the Governing Board of the South Coast Air Quality Management District (South Coast AQMD) determining that Proposed Amended Rule 1148.1 – Oil and Gas Production Wells, is exempt from the requirements of the California Environmental Quality Act (CEQA).**

**A Resolution of the South Coast AQMD Governing Board amending Rule 1148.1 – Oil and Gas Production Wells.**

**WHEREAS**, the South Coast AQMD Governing Board finds and determines that Proposed Amended Rule 1148.1 is considered a "project" as defined by CEQA; and

**WHEREAS**, the South Coast AQMD has had its regulatory program certified pursuant to Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l) and has conducted a CEQA review and analysis of the proposed project pursuant to such program (South Coast AQMD Rule 110); and

**WHEREAS**, the South Coast AQMD Governing Board finds and determines that after conducting a review of the proposed project in accordance with CEQA Guidelines Section 15002(k) – General Concepts, the three-step process for deciding which document to prepare for a project subject to CEQA, and CEQA Guidelines Section 15061 – Review for Exemption, procedures for determining if a project is exempt from CEQA, that Proposed Amended Rule 1148.1 is exempt from CEQA; and

**WHEREAS**, the South Coast AQMD Governing Board finds and determines that because the analysis of the anticipated physical changes that may occur as a result of implementing the proposed project indicates that minimal to no construction activities are expected, it can be seen with certainty that Proposed Amended Rule 1148.1 would not cause a significant adverse effect on the environment, and is therefore, exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3) – Common Sense Exemption; and

**WHEREAS**, the South Coast AQMD staff has prepared a Notice of Exemption for the proposed project, that is completed in compliance with CEQA Guidelines Section 15062 – Notice of Exemption; and

**WHEREAS,** the South Coast AQMD Governing Board has determined that the Final Socioeconomic Impact Assessment of Proposed Amended Rule 1148.1 is consistent with the March 17, 1989 Governing Board Socioeconomic Resolution for rule amendment; and

**WHEREAS,** the South Coast AQMD Governing Board has determined that the Final Socioeconomic Impact Assessment for Proposed Amended Rule 1148.1 is consistent with the provisions of Health and Safety Code Sections 40440.8, 40728.5, and 40920.6; and

**WHEREAS,** the South Coast AQMD Governing Board has determined that Proposed Amended Rule 1148.1 will result in increased costs to the affected industries, yet such costs are considered to be reasonable, with a total annualized cost as specified in the Final Socioeconomic Impact Assessment; and

**WHEREAS,** the South Coast AQMD Governing Board has actively considered the Final Socioeconomic Impact Assessment for Proposed Amended Rule 1148.1 and has made a good faith effort to minimize such impacts; and

**WHEREAS**, the South Coast AQMD staff conducted a Public Workshop on February 1, 2024 regarding Proposed Amended Rule 1148.1; and

**WHEREAS**, Proposed Amended Rule 1148.1 and supporting documentation, including but not limited to, the Notice of Exemption, Final Staff Report, and Final Socioeconomic Impact Assessment were presented to the South Coast AQMD Governing Board and the South Coast AQMD Governing Board has reviewed and considered this information, as well as has taken and considered staff testimony and public comment prior to approving the project; and

**WHEREAS**, the South Coast AQMD Governing Board finds and determines, taking into consideration the factors in Section (d)(4)(D) of the Governing Board Procedures (codified as Section 30.5(4)(D)(i) of the Administrative Code), that modifications to Proposed Amended Rule 1148.1 clause (e)(6)(B)(ii) since the Notice of Public Hearing was published, clarify the reference to Rule 1173 subdivision (g) and change the formatting of numeric value for consistency are not so substantial as to significantly affect the meaning of Proposed Amended Rule 1148.1 within the meaning of Health and Safety Code Section 40726 because: (a) the changes do not impact emission reductions, (b) the changes do not affect the number or type of sources regulated by the rule, (c) the changes are consistent with the information contained in the Notice of Public Hearing, and (d) the consideration of the range of CEQA alternatives is not applicable because the proposed project is exempt from CEQA; and

**WHEREAS**, Proposed Amended Rule 1148.1 will be submitted to California Air Resources Board (CARB) and United States Environmental Protection Agency (U.S. EPA) for inclusion into the State Implementation Plan; and

**WHEREAS**, Health and Safety Code Section 40727 requires that prior to adopting, amending, or repealing a rule or regulation, the South Coast AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the Final Staff Report; and

**WHEREAS,** the South Coast AQMD Governing Board has determined that a need exists to amend Rule 1148.1 to implement Best Available Retrofit Control

Technology, partially implement Control Measure FUG-01 of the 2022 Final Air Quality Management Plan, and fulfill commitments contained in the Wilmington, Carson, West Long Beach and South Los Angeles Community Emission Reduction Plans; and

**WHEREAS**, the South Coast AQMD Governing Board has determined that there is a problem that the proposed amended rule will alleviate, namely the failure to attain national ambient air quality standards for ozone and PM2.5, and that the rule will promote the attainment of state and federal ambient air quality standards; and

**WHEREAS**, the South Coast AQMD Governing Board obtains its authority to adopt, amend, or repeal rules and regulations from Health and Safety Code Sections 39002, 39650 et. seq., 40000, 40001, 40440, 40441, 40702, 40725 through 40728.5, 40920.6, and 41508; and

**WHEREAS**, the South Coast AQMD Governing Board has determined that Proposed Amended Rule 1148.1 is written and displayed so that its meaning can be easily understood by persons directly affected by it; and

**WHEREAS**, the South Coast AQMD Governing Board has determined that Proposed Amended Rule 1148.1 is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations; and

**WHEREAS**, the South Coast AQMD Governing Board has determined that Proposed Amended Rule 1148.1 does not impose the same requirements as any existing state or federal regulations, and the proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD; and

**WHEREAS**, the South Coast AQMD Governing Board, in amending Rule 1148.1, references the following statute which the South Coast AQMD hereby implements, interprets or makes specific: Assembly Bill 617, Health and Safety Code Sections 39002, 40001, 40406, 40702, 40440(a), 40725 through 40728.5, 40920.6, and 41511; and

**WHEREAS**, Health and Safety Code Section 40727.2 requires the South Coast AQMD to prepare a written analysis of existing federal air pollution control requirements applicable to the same source type being regulated whenever it adopts, or amends a rule, and the South Coast AQMD's comparative analysis of Proposed Amended Rule 1148.1 is included in the Final Staff Report; and

**WHEREAS**, the Public Hearing has been properly noticed in accordance with all provisions of Health and Safety Code Sections 40725 and 40440.5; and

**WHEREAS**, the South Coast AQMD Governing Board has held a Public Hearing in accordance with all provisions of law; and

**WHEREAS**, the South Coast AQMD Governing Board specifies the Planning, Rule Development, and Implementation Manager overseeing the rule development for Proposed Amended Rule 1148.1 as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of this proposed project is based, which are located at the South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, California; and

**NOW, THEREFORE BE IT RESOLVED,** that the South Coast AQMD Governing Board does hereby determine, pursuant to the authority granted by law, that Proposed Amended Rule 1148.1 is exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3) – Common Sense Exemption. This information has been presented to the South Coast AQMD Governing Board, whose members exercised their independent judgment and reviewed, considered, and approved the information therein prior to acting on the proposed project; and

**BE IT FURTHER RESOLVED**, that the South Coast AQMD Governing Board does hereby adopt, pursuant to the authority granted by law, Proposed Amended Rule 1148.1 as set forth in the attached, and incorporated herein by reference; and

**BE IT FURTHER RESOLVED,** that the South Coast AQMD Governing Board requests that Proposed Amended Rule 1148.1 be submitted for inclusion in the State Implementation Plan; and

**BE IT FURTHER RESOLVED,** that the Executive Officer is hereby directed to forward a copy of this Resolution and Proposed Amended Rule 1148.1 and supporting documentation to CARB for approval and subsequent submittal to the U.S. EPA for inclusion into the State Implementation Plan.

DATE: _______________ ______________________________

CLERK OF THE BOARDS

(Adopted March 5, 2004)(Amended September 4, 2015)(TBD)

# PROPOSED AMENDED RULE 1148.1. OIL AND GAS PRODUCTION WELLS

(a) Purpose

The purpose of this rule is to reduce emissions of volatile organic compounds (VOCs), toxic air contaminants (TAC) emissions and Total Organic Compounds (TOC) from the operation and maintenance of wellheads, well cellars, and the handling of produced gas at oil and gas production facilities to assist in reducing regional ozone levels and to prevent public nuisance and possible detriment to public health caused by exposure to such emissions.

(b) Applicability

This rule applies to onshore oil producing wells, well cellars and produced gas handling operation and maintenance activities at onshore facilities where petroleum and ~~processed~~ produced gas are produced, gathered, separated, processed and stored. These facilities are also subject to additional rule requirements, including, but not limited to: the storage of organic liquids is subject to Rule 463 – Organic Liquid Storage; wastewater systems, including sumps and wastewater separators are subject to Rule 1176 – VOC Emissions from Wastewater Systems; and leaks from components are subject to Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants. Natural gas distribution, transmission and associated storage operations are not subject to the requirements of this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) ABANDONED WELL is a well that has been certified by the California ~~Department of Conservation, Division of Oil, Gas and Geothermal Resources~~ Geologic Energy Management Division as permanently closed and non-operational.

(2) CENTRAL PROCESSING AREA is any location within an oil and gas production facility where pressurized phase separation or treatment of produced well fluids, including any produced oil, water or gas, occurs. A location that includes only oil producing wells and associated equipment not involved in pressurized phase separation or treatment, is not considered to be a central processing area.

(3) COMPONENT is any valve, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, wellhead, stuffing box, or meter in VOC service. Components are further classified as:

(A) MAJOR COMPONENT is any 4-inch or larger valve, any 5-hp or larger pump, any compressor, and any 4-inch or larger pressure relief device.

(B) MINOR COMPONENT is any component which is not a major component.

(4) CONFIRMED ODOR EVENT is an occurrence of odor resulting in three or more complaints by different individuals from different addresses, and the source of the odor is verified by ~~District~~ South Coast AQMD personnel.

(5) CONFIRMED OIL DEPOSITION EVENT is an occurrence of property damage due to the airborne release of oil or oil mist from an oil and gas production facility, as verified by ~~District~~ South Coast AQMD personnel.

(6) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOC's.

(~~6~~7) FACILITY is any equipment or group of equipment or other VOC-, TOC- or TAC-emitting activities, which are located on one or more contiguous properties within the ~~District~~South Coast AQMD, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility.

(8) FUEL CELL is a device that generates electricity through an electrochemical reaction, not combustion.

(9) GAS HANDLING is the control or processing of produced gas for on-site or off-site use.

(~~7~~10) HEAVY LIQUID is any liquid with 10 percent or less VOC by volume evaporated at 150ºC (302ºF), determined according to test methods specified in paragraph ~~(i)(3)~~(j)(3) or ~~(i)(4)~~(j)(4).

(~~8~~11) LEAK is the dripping of either heavy or light liquid; or the detection of a concentration of TOC above background, determined according to the test method in paragraph ~~(i)(1)~~(j)(1).

(~~9~~12) LIGHT LIQUID is any liquid with more than 10 percent VOC by volume evaporated at 150ºC (302ºF), determined according to the test method specified in paragraph ~~(i)(3)~~(j)(3).

(13) NEUTRALIZING AGENTS are chemical substances applied directly to the surface of the source of the odors in droplet or liquid form and are used to capture, destroy, and remove odorous molecules through a physio-chemical process that does not simply mask the odor.

(~~10~~14) ODOR is the perception experienced by a person when one or more chemical substances in the air come into contact with the human olfactory nerves.

(15) ODORANT is one or more chemical substances giving off a smell and that is deliberately used to mask another chemical substance's smell.

(~~11~~16) OIL PRODUCING WELL is a well which produces crude oil.

(17) OPTICAL GAS IMAGING (OGI) DEVICE is an infrared camera with a detector capable of visualizing gases in the 3.2-3.4 micrometer waveband.

(~~12~~18) ORGANIC LIQUID is any liquid containing VOC.

(~~13~~19) PRODUCED GAS is organic compounds that are both gaseous at standard temperature and pressure and are associated with the production, gathering, separation or processing of crude oil.

(~~14~~20) RESPONSIBLE PARTY for a corporation is a corporate officer. A responsible party for a partnership or sole proprietorship is the general partner or proprietor, respectively.

(~~15~~21) SENSITIVE RECEPTOR ~~means~~ is any residence including private homes, condominiums, apartments, and living quarters; education resources such as preschools and kindergarten through grade twelve (k-12) schools; licensed daycare centers; and health care facilities such as hospitals or retirement and nursing homes. A sensitive receptor includes long term care hospitals, hospices, prisons, and dormitories or similar live-in housing.

(~~16~~22) SPECIFIC CAUSE ANALYSIS is a process used by an owner or operator of a facility subject to this rule to investigate the cause of a confirmed odor event or confirmed oil deposition event, identify corrective measures and prevent recurrence of a similar event.

(23) STATIONARY GAS TURBINE is any gas turbine that is gas and/or liquid fueled with or without power augmentation. This gas turbine is either attached to a foundation at a facility or is portable equipment that will reside at the same location for more than 12 consecutive months.

(~~17~~24) STUFFING BOX is a packing gland, chamber or "box" used to hold packing material compressed around a moving pump rod to reduce the escape of gas or liquid.

(25) TIER 4 FINAL ENGINE is an engine subject to the final aftertreatment based Tier 4 emission standards in Title 13, Cal. Code Regs., Section 2423(b)(1)(B) and/or Title 40, CFR, Part 1039.101. This also includes engines certified under the averaging, banking, and trading program with respect to the Tier 4 FEL listed in Title 13, Cal. Code Regs., Section 2423(b)(2)(B) and/or Title 40, CFR, Part 1039.101.

(~~18~~26) TOTAL ORGANIC COMPOUNDS (TOC) is the concentration of gaseous organic compounds determined according to the test method in paragraph (i)(1).

(~~19~~27) TOXIC AIR CONTAMINANT (TAC) is an air contaminant that has been identified as a hazardous air pollutant pursuant to Section 7412 of Title 42 of the United States Code; or has been identified as a TAC by the California Air Resources Board (CARB) pursuant to Health and Safety Code Section 39655 through 39662; or which may cause or contribute to an increase in mortality or an increase in serious illness, or potential hazard to human health.

(28) VISIBLE VAPORS are any VOC vapors detected visually by an operator or detected with an OGI device during a well cellar, wellhead, oil producing well, or water injection well inspection.

(~~20~~29) VOLATILE ORGANIC COMPOUND is as defined in Rule 102 – Definition of Terms.

(~~21~~30) WASTEWATER is a water stream or other liquid waste stream generated in a manner which may contain petroleum liquid, emulsified oil, VOC, or other hydrocarbons.

(~~22~~31) WATER INJECTION WELL is a bored, drilled, or driven shaft, or a dug hole that is deeper than it is wide, or an improved sinkhole, or a subsurface fluid distribution system used to inject fluid consisting primarily of water into a reservoir typically to create fluid lift of product or maintain reservoir pressure.

(~~23~~32) WELL CELLAR is a lined or unlined containment surrounding one or more oil wells, allowing access to the wellhead components for servicing and/or installation of blowout prevention equipment.

(~~24~~33) WELLHEAD is an assembly of valves mounted to the casing head of an oil well through which a well is produced. The wellhead is connected to an oil production line and in some cases to a gas casing line.

(34) WORKOVER RIG is a mobile piece of equipment used to perform one or more operations on an oil producing well or water injection well.

(d) Requirements

(1) The operator of an oil and gas production facility shall not allow a concentration of a TOC in the well cellar greater than 500 ppmv, according to the test method in paragraph ~~(i)(1)~~(j)(1).

(2) The operator of an oil and gas production facility shall not allow any valve to be opened at the wellhead unless a portable container is used to catch and contain organic liquid that would otherwise drop into the well cellar or onto the ground. Such container shall be kept closed to the atmosphere when it contains organic liquid and is not in use.

(3) If a well cellar is verified by ~~District~~ South Coast AQMD personnel as the source of odors associated with three or more complaints by different individuals from different addresses in a single day, the operator of an oil and gas production facility shall pump out or remove organic liquid accumulated in the well cellar as soon as possible but no later than by the end of the day.

(4) The operator of an oil and gas production facility shall not allow organic liquid to be stored in a well cellar, except as provided by paragraph (d)(5). During any period of equipment maintenance, drilling, well plugging, abandonment operations, or well workover, the operator shall pump out or remove organic liquid that accumulates in the well cellar no later than two (2) days after the maintenance, drilling, well plugging, abandonment or workover activity at the well is completed.

(5) The operator may only store organic liquid in a portable enclosed storage vessel if the vessel is equipped with air pollution control equipment to reduce the TOC emissions to less than 250 ppmv outlet concentration according to the test method in paragraph ~~(i)(1)~~(j)(1), except use of air pollution control equipment is not required during activities determined to meet the exemption criteria of paragraph ~~(j)(2)~~(k)(2). The operator shall conduct a TOC measurement according to the test method in paragraph ~~(i)(1)~~(j)(1) at the time of filling, and weekly thereafter to ensure that the air pollution control system achieves the emission standard of 250 ppmv.

(6) The operator of an oil and gas production facility shall pump out any organic liquid accumulated in the well cellar immediately before a well is steamed or after a wellhead is steam cleaned.

(7) The operator of an oil and gas production facility shall pump out or remove organic liquid accumulated in the well cellar when the TOC concentration in the well cellar is greater than 250 ppmv as determined by the test method in paragraph ~~(i)(1)~~<u>(j)(1)</u> within five (5) calendar days following the determination, or if the well cellar is located within 1,500 feet of a sensitive receptor, by close of the following ~~business~~ day. In lieu of the method in paragraph ~~(i)(1)~~<u>(j)(1)</u>, an operator may measure the depth of accumulated organic liquid and pump-out the liquid when the depth exceeds two (2) inches. The organic liquid depth may be measured using a "copper coat" gauge or any other measuring instrument determined to be acceptable by the Executive Officer.

(8) The operator of an oil and gas production facility shall not allow natural gas or produced gas to be vented into the atmosphere. The emissions of produced gas shall be collected and controlled using one of the following:

(A) A system handling gas for fuel, sale, or underground injection; or

(B) A device, approved by the Executive Officer, with a VOC vapor removal efficiency demonstrated to be at least 95% by weight per test method of paragraph ~~(i)(2)~~<u>(j)(2)</u> or by demonstrating an outlet VOC concentration of 50 ppmv according to the test method in paragraph ~~(i)(1)~~<u>(j)(1)</u> or by an equivalent demonstration identified in an approved permit issued on or after March 5, 2004, pursuant to Rule 203 – Permit to Operate. If the control device uses supplemental natural gas to control VOC, it shall be equipped with a device that automatically shuts off the flow of natural gas in the event of a flame-out or pilot failure.

(9) Except as Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants applies to components of produced gas handling equipment located within 100 meters of a sensitive receptor, the operator shall repair any gaseous leaks of 250 ppmv TOC or greater by the close of the ~~business~~ day following the leak discovery or take actions to prevent the release of TOC emissions to the atmosphere until repairs have been completed.

(10) Unless approved in writing by the Executive Officer, CARB, and United States Environmental Protection Agency (U.S. EPA) as having no significant emissions impacts, no person shall:

(A) Remove or otherwise render ineffective a well cellar at an oil and gas production well except for purposes of well abandonment to be certified by the California ~~Department of Conservation, Division of Oil, Gas and Geothermal Resources~~ Geologic Energy Management Division; or

(B) Drill a new oil and gas production well unless a well cellar is installed for secondary containment of fluids.

(11) ~~Effective October 4, 2015, t~~The operator of an oil and gas production facility shall utilize a rubber grommet designed for drill piping, production tubing or sucker rods to remove excess or free flowing fluid from piping, tubing or rods that are removed during any maintenance or piping, tubing or rod replacement activity that involves the use of a workover rig.

(12) ~~Effective March 2, 2016, t~~The operator of an oil and gas production facility shall, for any central processing area located within 1,500 feet of a sensitive receptor, operate and maintain a monitoring system that alarms or notifies operators of key process conditions, such as operating pressure, liquid level or on/off operating status, or a monitoring system that is required in accordance with applicable local fire regulations, in order to ensure proper facility operation. The monitoring system shall alarm or notify operators at a central location, control center, or other common area. The owner or operator shall identify and document the monitored process parameters or monitoring system required by applicable local fire regulations and shall make such documentation available for inspection upon request.

(13) Effective [six months from date of rule amendment]~~October 4, 2015~~, the operator of an oil and gas production facility shall ~~post instructions~~ install and maintain signage. Unless otherwise approved in writing by the Executive Officer, signage shall:~~for reporting odor complaints. The posted instructions shall be provided in a conspicuous manner and under such conditions as to make it likely to be read or seen and understood by an ordinary individual during both normal operating and non-operating hours. The instructions shall include the following minimum information in English and Spanish:~~

(A) Be installed within 50 feet of the main entrance to the facility and in a location that is visible to the public;

(B) Measure at least 30 inches wide by 30 inches tall;

(C) Display lettering at least 2 inches tall with text color contrasting with the sign background;

(D) Located at least 4 feet above grade from the bottom of the sign;

(E) Display the following information in English and Spanish:

(~~A~~i) ~~Name of the facility~~Local or toll-free phone number for the site contact that is accessible 24 hours a day;

(~~B~~ii) ~~Facility call number; and,~~Notification statement:
"TO REPORT AIR QUALITY ISSUES SUCH AS ODORS, DUST, OR SMOKE FROM THIS FACILITY, PLEASE CALL [FACILITY CONTACT AND PHONE NUMBER] OR THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT AT 1-800-CUT-SMOG®"; and

(~~C~~iii) ~~Instructions to call the South Coast Air Quality Management District complaint hotline at the toll free number 1-800-CUT-SMOG or equivalent information approved in writing by the Executive Officer.,~~Notification statement:
"PARA REPORTAR PROBLEMAS DE CALIDAD DEL AIRE COMO OLORES, POLVO O HUMO DE UNA INSTALACIÓN, LLAME A [CONTACTO DE LA INSTALACIÓN Y NÚMERO DEL TELÉFONO] O AL EL DISTRITO DE ADMINISTRACIÓN DE LA CALIDAD DEL AIRE DE LA COSTA SUR AL 1-800-CUT-SMOG®"; and

(iv) Instructions to access additional information electronically:
https://www.aqmd.gov/home/rules-compliance/compliance/1148-2

(14) The operator of an oil and gas production facility shall maintain well cellar, wellhead, oil producing well, water injection well and associated lines free of visible vapors resulting from a defect in equipment as determined pursuant to the schedule and inspection requirements specified in paragraph (e)(6).

(15) Effective [Two years from date of rule amendment], any engine that is powered by produced gas that is used to operate an oil producing or injection well shall comply with a NOx emission limit of 11 ppmv at 15% oxygen on a dry basis.

(16) Effective [Two years from date of rule amendment], any stationary gas turbine or fuel cell that is powered by produced gas, at an oil and gas production facility, shall comply with a NOx emission limit of 9 ppmv at 15% oxygen on a dry basis

(17) Effective [Three years from date of rule amendment], workover rigs operated at an oil and gas production facility shall be equipped with an engine that meets the minimum emissions standards of a Tier 4 Final engine.

(18) The operator of an oil and gas production facility shall not use odorants.

(19) The operator of an oil and gas production facility shall not:

(A) Use a neutralizing agent that contains more than 0.1 % by weight of toxic air contaminants pursuant to South Coast AQMD Rule 1401 – New Source Review of Toxic Air Contaminants; and

(B) Atomize or spray any neutralizing agent.

(20) Effective January 1, 2025, for any leaks that are detected within a well cellar or from a wellhead that are greater than 25,000 ppm VOC with a calibrated analyzer per EPA Method 21, the operator shall electronically notify the Executive Officer, using a format approved by the Executive Officer, of the following information within 24 hours of the leak quantification:

(A) name and contact information of the owner and operator of the subject wellhead(s) and/or well cellar(s);

(B) leak concentration(s) in parts per million (PPM);

(C) date of discovery; and

(D) status of any repairs.

(e) Operator Inspection Requirements

(1) The operator of an oil and gas production facility shall visually inspect:

(A) Any stuffing box not located in or above a well cellar daily;

(B) Any stuffing box located in or above a well cellar weekly; or

(C) Any stuffing box or produced gas handling and control equipment located 328 feet (100 meters) or less from a sensitive receptor daily. Receptor distance shall be determined as the distance measured from the stuffing box or produced gas handling and control equipment to the property line of the nearest sensitive receptor.

(D) Any stuffing box or produced gas handling and control equipment located between 328 feet (100 meters) and 1,500 feet from a sensitive receptor daily for any facility receiving Notice(s) of Violation for Rule 402 and/or H&S Code § 41700 for odor nuisance occurring on two (2) or more days. Receptor distance shall be determined as the distance measured from the stuffing box or produced gas handling and control equipment to the property line of the nearest sensitive receptor.

(2) Notwithstanding the requirements of subparagraphs (e)(1)(A) and (e)(1)(B), the operator shall perform monthly visual inspections of any stuffing box fitted with a stuffing box adapter, any closed crude oil collection container, and any well shut off switch that will shut down the well when the container is full.

(3) Except for well cellars listed under subdivision (~~i~~j), the operator shall quarterly, perform an inspection of all well cellars according to the test method in paragraph ~~(i)(1)~~(j)(1).

(4) Within two (2) days of discovery of organic liquid leakage observed from the inspections pursuant to subparagraph (e)(1)(A), (e)(1)(B), or paragraph (e)(2), and within eight (8) hours pursuant to subparagraph (e)(1)(C), the operator shall conduct an inspection of the stuffing box and well cellar according to the test method in paragraph ~~(i)(1)~~(j)(1) or measure the organic liquid depth using a "copper coat" gauge or any other measuring instrument determined to be acceptable by the Executive Officer.

(5) Notwithstanding the provisions of Rule 1173 – Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants, the operator of an oil and gas production facility shall conduct a monthly TOC measurement on any component that has been identified as causing or likely to have caused the confirmed odor event through a submitted specific cause analysis report submitted in accordance with the provisions of subdivision (f). The TOC measurement shall be conducted monthly according to the test method in paragraph ~~(i)(1)~~(j)(1) following submittal of the specific cause analysis report, until the measurement fails to exceed the leak rates identified in subparagraphs (e)(5)(A) and (e)(5)(B) for six consecutive months. The operator shall

repair, replace or remove from service the component in accordance with the requirements of subparagraphs (e)(5)(A) and (e)(5)(B).

(A) Any heavy liquid component leak of more than three drops per minute and greater than 100 ppmv shall be repaired, replaced or removed from service in one (1) calendar day.

(B) Any light liquid/gas/vapor/component leak greater than 500 ppmv but no more than 10,000 ppmv shall be repaired, replaced or removed from service in one (1) calendar day.

(6) Optical Gas Imaging Inspections

Effective [six months from rule amendment], the operator of an oil and gas production site shall demonstrate compliance with subparagraph (d)(14), by conducting OGI inspections in accordance with the following requirements:

(A) The person conducting an OGI inspection shall:

(i) Complete a manufacturer's certification or training program for the OGI Device used to conduct the inspection, and

(ii) Operate and maintain the OGI Device in accordance with the manufacturer's specifications and recommendations.

(B) Oil and Gas Production Facility Inspections

A person meeting the requirements of subparagraph (e)(6)(A) shall:

(i) Conduct an inspection at an oil and gas production facility at least once per calendar month on all components and well cellars; and

(ii) When visible vapors are detected using an OGI Device, and the leak cannot be repaired within ~~twenty-four~~ 24 hours from time of discovery, the use of an appropriate analyzer in compliance with paragraph (j)(1) shall be used to quantify the visible vapors in ppmv concentration within 48 hours of when the vapors are detected and the leak shall be repaired pursuant to Rule 1173 subdivision (g)~~the Repair Period Table from Rule 1173~~. Quantification of visible vapors is not required if the leak is repaired within ~~twenty-four~~ 24 hours from time of discovery.

(f) Specific Cause Analysis and Report

Effective September 4, 2015, the owner or operator of any oil and gas production facility with any sensitive receptor within 1,500 feet of any well located on the facility property shall conduct a Specific Cause Analysis for each confirmed odor event and for each confirmed oil deposition event. The Specific Cause Analysis shall describe the steps taken to identify the source and cause of the odor or confirmed oil deposition event, and any mitigation and corrective actions taken or identified. The owner or operator shall, within 30 calendar days following receipt of written notification of a confirmed odor event or confirmed oil deposition event from the Executive Officer, submit the Specific Cause Analysis report to the Executive Officer, certified by the Responsible Party that all information submitted is true and correct.

(1) The submitted Specific Cause Analysis report shall include the following:

(A) Identification of the equipment or activity causing or likely to have caused the confirmed odor event or confirmed oil deposition event, including any equipment or activity identified in the written notification of a confirmed odor event or confirmed oil deposition event by the Executive Officer.

(B) Any ~~SCAQMD~~ <u>South Coast AQMD</u> regulatory requirement associated with the equipment or activity causing or likely to have caused the confirmed odor event or confirmed oil deposition event, including but not limited to, any permit condition and any other ~~SCAQMD~~ <u>South Coast AQMD</u> rule, including this rule.

(C) Identification of any Standard Operating Procedure, emergency or leak prevention plan, including any spill prevention plan, preventative maintenance scheduling or procedure associated with the source of the confirmed odor event or confirmed oil deposition event and any corrective action identified as part of the review and update pursuant to paragraph (f)(2) and schedule for completion of the corrective action.

(2) The owner or operator shall review and update the following as part of the Specific Cause Analysis:

(A) Any Standard Operating Procedures associated with normal production operations and the leak history of inspections associated with the source of the confirmed odor event or confirmed oil deposition event.

(B) Any emergency or leak prevention plans, including any spill prevention plans associated with the source of the confirmed odor event or confirmed oil deposition event.

(C) Any preventative maintenance scheduling or procedures associated with the source of the confirmed odor event or confirmed oil deposition event.

(g) Odor Mitigation Plan

Effective September 4, 2015, the owner or operator of any oil and gas production facility shall submit for approval an Odor Mitigation Plan, or an update to an existing Odor Mitigation Plan, to the Executive Officer within 90 calendar days following receipt of written notification from the Executive Officer.

(1) Requirement for a Plan Submittal

The Executive Officer shall notify the owner or operator of any oil and gas production facility with any sensitive receptor within 1,500 feet of any well located on the facility property of the requirement for an Odor Mitigation Plan if any of the following thresholds are met or exceeded:

(A) Receipt of Notice(s) of Violation for Rule 402 and/or H&S Code § 41700 for odor nuisance occurring on two (2) or more days; or

(B) Three (3) confirmed odor events within the previous six (6) consecutive calendar months.

(C) Subsequent to approval of an Odor Mitigation Plan:

(i) Receipt of a Notice of Violation for Rule 402 – Nuisance, as a result of odors; or

(ii) Three (3) confirmed odor events within the most recent six (6) consecutive calendar months following the date of approval of a previous Odor Mitigation Plan.

(2) Odor Mitigation Plan Elements

An approved Odor Mitigation Plan must include and address the following activities and equipment:

(A) Oil and gas production and wastewater generation, including both normal and spill or release management control operations, with corresponding identification of potential or actual sources of emissions, odors, frequency of operator inspection and history of leaks.

(B) Activity involving drilling, well completion or rework, repair or maintenance of a well, which notes the sources of emissions, odors, odor mitigation measures for responding to odors and odor complaints, and procedures used for odor monitoring at the site and fence line.

(C) Identification of emission points and emission or leak monitoring used for all wastewater tanks, holding, knockout, and oil/water separation vessels, including any pressure relief devices or vacuum devices attached to the vessels, with provisions for recording of releases from such devices.

(D) Any equipment or activity identified as part of any previous Specific Cause Analysis.

(3) Odor Monitoring and Mitigation Requirements

An approved Odor Mitigation Plan must include the following odor monitoring and mitigation provisions:

(A) The owner or operator shall conduct continual odor surveillance downwind at the perimeter of the property during drilling, well completion, or rework, repair or maintenance of any well, including water injection wells. Observations shall be recorded hourly. Equivalent odor monitoring equipment may be used in lieu of odor surveillance, subject to approval by the Executive Officer.

(B) If odors are detected from odor surveillance or odor monitoring at the perimeter of the facility, pursuant to subparagraph (g)(3)(A) and confirmed from drilling, well completion, or rework, repair or maintenance of any well, the associated activity will discontinue until the source or cause of odors is determined and mitigated in accordance with measures previously approved unless the source or cause of the detected odors is determined to not be associated with the activity under surveillance.

(C) The oil and gas production facility shall store any removed drill piping, production tubing or sucker rods in a manner that minimizes emissions from crosswinds by storing within an enclosed area or other equivalent method.

(D) Notwithstanding the provisions of Rule 1173 - Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants, the operator of any oil and gas production facility shall repair, replace or remove from service any leaking component located within 1,500 feet of a sensitive receptor in accordance with the requirements of clauses (g)(3)(D)(i) and (g)(3)(D)(ii). For each calendar quarter, the operator may extend the repair period, as indicated below, for a total number of leaking components not to exceed 0.05 percent of the number of components inspected during the previous quarter, by type, rounded upward to the nearest integer where required.

(i) Any heavy liquid component leak of more than three drops per minute and greater than 100 ppmv shall be repaired, replaced or removed from service in one (1) calendar day with an extended repair period of three (3) calendar days.

(ii) Any light liquid/gas/vapor component leak greater than 500 ppmv but no more than 10,000 ppmv shall be repaired, replaced or removed from service in one (1) calendar day with an extended repair period of three (3) calendar days.

(E) Any corrective action identified in a Specific Cause Analysis report previously submitted by the facility.

(F) The owner or operator shall evaluate the cause or likely cause of any confirmed odor event as identified in any Specific Cause Analysis report previously submitted by the facility and identify either improvements to existing monitoring systems required pursuant to paragraph (d)(12) or parameters for a new monitoring system installation. The owner or operator shall establish an installation and implementation schedule for any monitoring system improvements or new installations, subject to Executive Officer approval.

If any provision of paragraph (g)(3) is not included in the Odor Mitigation Plan, an evaluation and documentation must be provided in the Odor Mitigation Plan that states the reason why such provision is not feasible or would not be effective in addressing the specific cause of the confirmed odor events or notice(s) of violation that resulted in the requirement for plan submittal, subject to approval by the Executive Officer.

(4) The owner and operator of an oil and gas production facility shall comply with all provisions of an approved Odor Mitigation Plan, except as provided by paragraph ~~(j)(2)~~(k)(2). Violation of any of the terms of the plan is a violation of this rule.

(h) Recordkeeping Requirements

(1) The operator shall maintain all records that document the purchase and installation of the stuffing box adapter(s) to demonstrate compliance with paragraph (e)(4) at the facility or facility headquarters and such records shall be made available to the Executive Officer upon request.

(2) The operator shall maintain all records of inspection, measurements, repair, cleaning and pump-outs required by this rule, and of any activities performed under the exemption provided by (~~j~~k)(2), in a form approved by the Executive Officer at the facility or facility headquarters for a period of three years or a period of five years for a Title V facility and such records shall be made available to the Executive Officer upon request.

(3) The operator shall maintain production records and other applicable information and documents, including any referenced established written company safety manual or policy, sufficient to demonstrate eligibility for any exemption claimed pursuant to subdivision ~~(i)~~(j) and make them available to the Executive Officer upon request.

(4) The operator shall maintain all records and other applicable documents required as part of an Odor Mitigation Plan approved in accordance with subdivision (g) in a form approved by the Executive Officer at the facility or facility headquarters for a period of three years or a period of five years for a Title V facility and such records and applicable documents shall be made available to the Executive Officer upon request.

(i) Testing Requirements

(1) For any engine subject to paragraph (d)(15), the operator shall demonstrate compliance to the emission limit in paragraph (d)(15) by:

(A) Conducting an initial source test within [24 months of rule amendment]; and

(B) Subsequent source testing within 5 years of the previous source test.

(2) For any stationary turbine subject to paragraph (d)(16), the operator shall demonstrate compliance to the emission limit in paragraph (d)(16) by:

(A) Conducting an initial source test within [24 months of rule amendment]; and

(B) Subsequent source testing within 5 years of the previous source test.

(~~i~~j) Test Methods

The following test methods and procedures shall be used to determine compliance with this rule. Other test methods determined to be equivalent after review by the staffs of the ~~District~~South Coast AQMD, ~~the Air Resources Board~~CARB, and the U.S. EPA, and approved in writing by the ~~District~~ Executive Officer may also be used.

(1) Measurement of TOC or VOC concentrations shall be conducted according to the ~~United States Environmental Protection Agency (~~U.S. EPA~~)~~ Reference Method 21 using an appropriate analyzer calibrated with methane. The analyzer shall be calibrated before inspection each day prior to use. For the purpose of demonstrating compliance with the TOC concentration requirements in paragraphs (d)(1) and (d)(7), measurement of the TOC concentrations shall be conducted at a distance of no more than three (3) inches above the organic liquid surface in the well cellar.

(2) Determination of Efficiency of Emission Control Systems

The control equipment efficiency of an emission control system, on a mass emissions basis, and the VOC concentrations in the exhaust gases, measured and calculated as carbon, shall be determined by U.S. EPA Test Methods 25, 25A, or ~~District~~ South Coast AQMD Method 25.1 - Determination of Total Gaseous Non-Methane Organic Emissions as Carbon or ~~District~~ South Coast AQMD Method 25.3 Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions from Clean Fueled Combustion Sources, as applicable. U.S. EPA Test Method 18 or CARB Method 422 shall be used to determine emissions of exempt compounds.

(3) The VOC content shall be determined according to ASTM Method D 1945 for gases, ~~SCAQMD~~ South Coast AQMD Method 304-91 for liquids. The percent VOC of a liquid evaporated at 150ºC (302ºF) shall be determined according to ASTM Method D 86.

(4) The flash point of heavy liquids shall be determined according to ASTM Method D 93.

(5) Laboratory Approval

Sampling, analysis, and reporting shall be conducted by a laboratory that has been approved under the ~~District~~ South Coast AQMD Laboratory Approval Program (LAP) for the cited ~~District~~ South Coast AQMD reference test methods, where LAP approval is available. For ~~District~~ South

Coast AQMD reference test methods for which no LAP program is available, the LAP approval requirement shall become effective one year after the date that the LAP program becomes available for that ~~District~~ South Coast AQMD reference test method.

(6) Source testing for compliance demonstration of NOx emission limits shall be conducted per South Coast AQMD Method 100.1.

(~~j~~k) Exemptions

(1) This rule shall not apply to well cellars associated exclusively with:

(A) Oil and gas production wells that have been idle and out of operation for more than six months, as indicated by production records, with no liquid leaks or accumulation of crude oil in the well cellar. All provisions of this rule shall apply upon commencement of operation of the idle well.

(B) Wells that have been certified as an abandoned well by the California ~~Department of Conservation, Division of Oil, Gas and Geothermal Resources~~ Geologic Energy Management Division.

(C) Water, gas or steam injection wells.

(2) The provisions of paragraphs (d)(3), (d)(5), (d)(7), (d)(8), (d)(9) and paragraph (g)(3) shall not apply to any well, produced gas handling system, or portable enclosed storage vessel and associated air pollution control equipment undergoing maintenance and repair, well drilling, or well abandonment operations, if the owner or operator can demonstrate to the Executive Officer that: performing the maintenance and repair, drilling, or abandonment operation to meet paragraph (d)(3), (d)(5), (d)(7), (d)(8), (d)(9), or paragraph (g)(3), as applicable, would cause the facility to operate in a manner that violates state or federal regulations, applicable industry safety standards, or a written company safety manual or policy that was developed to comply with applicable industry safety standards; and that the maintenance and repair, drilling, or abandonment operation is conducted in a manner that minimizes, as much as possible under the circumstances, emissions to the atmosphere.

(3) The provisions of paragraph (d)(1), (d)(2) and (d)(7) shall not apply to any well cellar used in emergencies at oil production facilities, if clean-up procedures are implemented within 24 hours after each emergency occurrence and completed within ten (10) calendar days.

(4) The provisions of paragraph (d)(8) of this rule shall not apply to oil and gas production wells in operation as of March 5, 2004, that produce no more than one (1) barrel per day of oil or 200 standard cubic feet per day of produced gas per facility, provided that such production wells are not located within 100 meters of a sensitive receptor, and provided the production can be demonstrated from annual production records. Demonstration of produced gas production shall be based on metered measurement of the gas.

(5) The provisions of paragraph (i)(2) shall not apply to a stationary turbine certified by the CARB Distributed Generation Certification Program.

**SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT**

# Final Staff Report
# Proposed Amended Rule 1148.1 – Oil and Gas Production Wells

## July 2024


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| | |
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<u>EXECUTIVE OFFICER:</u>

WAYNE NASTRI

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## EXECUTIVE SUMMARY

The purpose of South Coast AQMD Rule 1148.1 – *Oil and Gas Production Wells* (Rule 1148.1) is to reduce emissions of volatile organic compounds (VOC), toxic air contaminants (TAC) and total organic compounds (TOC) from the operation and maintenance of wellheads, well cellars, and the handling of produced gas and oil and gas production facilities. Rule 1148.1 applies to approximately 330 onshore oil or gas well facilities that conduct operations including drilling, well completion, well rework, and well injection activities.

~~PAR 1148.1 iswill also seek to further reduce VOC emissions from wellheads, well cellars, and the handling of produced gas through use of enhanced leak detection technology.~~

Rule requirements reduce VOC emissions from the wellheads and the well cellars through inspection and maintenance, and control of produced gas emissions. The rule also establishes work practices and odor mitigation procedures.

Proposed Amended Rule 1148.1 (PAR 1148.1) will seek to further reduce VOC emissions from wellheads, well cellars, and the handling of produced gas through use of enhanced leak detection technology, among other requirements.

~~In response to concerns raised by Assembly Bill (AB) 617 communities located in the Wilmington, Carson, West Long Beach (WCWLB) area and South Los Angeles (SLA) area and the 2022 Air Quality Management Plan Control Measure FUG-01: Improved Leak Detection and Repair, Proposed Amended Rule (PAR) 1148.1 will further reduce and control VOC emissions. Proposed Amended Rule (~~PAR~~)~~ 1148.1 was developed in response to priorities identified in the Wilmington, Carson, West Long Beach (WCWLB) Community Emission Reduction Plan (CERP), the South Los Angeles~~[2]~~ (SLA) CERP, and to partially implement the 2022 Air Quality Management Plan (AQMP) control measure FUG-01: Improved Leak Detection and Repair. PAR 1148.1 will: 1) add new definitions to further clarify the amendments being proposed, 2) require the use of enhanced leak detection technology, 3) require equipment that uses produced gas to meet specific NOx limits and to verify compliance via source tests, 4) require workover rigs to use Tier 4 Final diesel engines, 5) ban the use of odorants that are used to mask odors emanating from oil production sites, 6) require submitting a notification for quantified leaks greater than 25,000 ppm VOC, and ~~6~~7) update signage requirements. Additional minor changes to rule language will be made for consistency and clarity.

Implementation of PAR 1148.1 is expected to reduce VOC emissions by approximately 100 tons per year (0.27 tons per day) starting in year 2025~~ when the OGI inspections begin~~, and is expected to reduce NOx emissions by approximately 200 tons per year (0.55 tons per day) by year 2027 ~~when workover rigs are required to meet Tier 4 Final engine standards~~.

Development of PAR 1148.1 was conducted through a public process. Four Working Group Meetings were held on: April 20, 2023, September 14, 2023, December 14, 2023, and April 11,

2024. The working group meetings consist~~s~~ of stakeholders including representatives from the communities, environmental organizations, industry representatives, and government agencies. In addition, staff participated in AB 617 meetings to notify and update stakeholders on the rule development process. Staff also met ~~individually~~ with industry stakeholders and visited sites affected by the rule development process. ~~Working group meeting notices were provided to operators, suppliers and participants of AB 617 meetings that signed up for notifications of AB 617 updates or oil and gas well rule development.~~ A Public Workshop ~~meeting~~ was held on February 1, 2024, where staff presented ~~the proposed amended rule~~PAR 1148.1 to the ~~general~~ public and stake-holders, and received comments related to the proposals.

# CHAPTER 1: BACKGROUND

## INTRODUCTION

Rule 1148.1 – *Oil and Gas Production Wells* requires operators of oil and gas wells to reduce emissions of volatile organic compounds (VOCs), toxic air contaminants (TAC) emissions and Total Organic Compounds (TOC) from the operation of wellheads, well cellars, and the handling of produced gas at oil and gas production facilities. Well activity occurs at multiple sites throughout the South Coast AQMD and may be found near residential communities as shown in Figure 1.1.

Figure 1.1 – Example of Urban Oil Well

Concerns have been raised by AB 617 communities located in the Wilmington, Carson, West Long Beach (WCWLB) area and South Los Angeles (SLA) area about the need for additional, timely and reliable requirements to further control VOC emissions coming from oil and gas production facilities. In response, staff proposes to modify requirements in Rule 1148.1 to add the use of enhanced leak detection technology, require Tier 4 Final diesel engines in the use of workover rigs engaged in general maintenance activities, and source test requirements for stationary equipment that uses produced gas to verify emission limits. Staff also proposes to ban the use of odorants used to mask odors and update signage requirements. Additional definitions and minor changes to rule language are made for consistency and clarity.

## REGULATORY BACKGROUND

Rule 1148.1 was adopted on March 5, 2004, to implement Control Measure FUG-05 of the 2003 AQMP by reducing VOC emissions from the wellheads and the well cellars located at oil and gas production facilities through increased inspection and maintenance, and control of produced gas emissions, with additional regulatory considerations when located within 100 meters to sensitive receptors. See Figure 1.2 for an example of wellheads inside a well cellar.


Figure 1.2 – Example of Wellheads Inside a Well Cellar

Rule 1148.1 was amended on September 4, 2015 to minimize environmental impacts on neighboring communities and sensitive receptors from ongoing operations, including well stimulation techniques such as hydraulic fracturing. Between 2010 and 2014, operations at an urban oil and gas production facility were the subject of numerous public complaints and received multiple Notices of Violations (NOV) from the South Coast AQMD. The amendment focused on improving work practices and established odor mitigation procedures.

*AB 617 and Concerns with Oil and Gas Well Activities*

In 2017, Governor Brown signed AB 617 (C. Garcia, Chapter 136, Statutes of 2017) to develop a new community-focused program to potentially reduce exposure to air pollution and preserve public health. AB 617 directed the California Air Resources Board (CARB) and all local air districts, including the South Coast AQMD, to enact measures to protect communities disproportionally impacted by air pollution. On September 27, 2018, CARB designated 10 communities across the state to implement community plans for the first year of the AB 617 program. Local air districts were tasked with developing and implementing community emissions reduction and community air monitoring plans in partnership with residents and community stakeholders. The Community Air Monitoring Plan (CAMP) includes actions to enhance the understanding of air pollution in the designated communities and to support effective implementation of the Community Emissions Reduction Plan (CERP). A CERP provides a blueprint for achieving air pollution emission and exposure reductions, addressing the community's highest air quality priorities. The CERP includes actions to reduce emissions and/or exposures in partnership with community stakeholders.

During their CERP development process, the WCWLB and SLA communities raised numerous concerns related to oil and gas well activity and current South Coast AQMD rules.

The CERP for WCWLB listed four main air quality priorities related to oil drilling and production. These priorities focused on:

- The need for near-facility air measurements and inspections to address leaks and odors from oil drilling and production;
- Fenceline air monitoring;
- Vapor recovery systems and leak detection technologies; and
- The use of lower or zero-emission equipment for on-site operations.

The CERP for SLA also listed multiple priorities related to oil drilling and production. These priorities focused on:

- Identification of potential elevated emissions through air measurement surveys around oil drilling sites;
- Determination of which oil well sites and activities may require additional monitoring;
- Explore limiting/eliminating odorant use;
- Explore requirements for lower emission or zero-emission equipment;
- Reduction emissions and exposure to oil and gas operations through rule amendments to the Rule 1148 Series;
- Incentive funding opportunities for best management practices and/or installation of emission reduction technologies at oil and gas facilities.

Note that some other community concerns have been addressed in the February 2023 amendment to *Rule 1148.2 – Notification and Reporting Requirements for Oil and Gas Wells and Chemical Suppliers* (Rule 1148.2) such as providing notifications for activities such as acidizing of water injection wells. In addition, Rule 1148.2 has requirements for mailers to be sent out to sensitive receptors within 1,500 feet of an oil and gas or injection well prior to the commencement of an acidizing event.

## AFFECTED FACILITIES

Proposed Amended Rule 1148.1 affects any operator of an oil or gas production facility located within the jurisdiction of the South Coast AQMD and its operation and maintenance of wellheads, well cellars, and the handling of produced gas. There are approximately three hundred and thirty facilities potentially affected by this amendment.

## PUBLIC PROCESS

The development of PAR 1148.1 was conducted through a public process. Four Working Group Meetings were held on: April 20, 2023, September 14, 2023, December 14, 2023, and April 11, 2024. In addition, staff participated in AB 617 meetings to notify and update stakeholders on the rule development process. Stakeholders include representatives from the community, environmental organizations, industry representatives, and government agencies. Staff also met individually with industry stakeholders and visited sites affected by the rule development process.

Working group meeting notices were provided to operators, suppliers and participants of AB 617 meetings that signed up for notifications of AB 617 updates or oil and gas well rule development. A Public Workshop meeting was held on February 1, 2024, where staff presented the proposed amended rule to the general public and stake holders, and received comments related to the proposal.

# CHAPTER 2: BARCT ASSESSMENT

## INTRODUCTION

As part of the rule development process, staff conducted a Best Available Retrofit Control Technology (BARCT) assessment of equipment subject to PAR 1148.1. The purpose of a BARCT assessment is to identify potential emission reductions from specific equipment and to establish an emission limit consistent with state law.

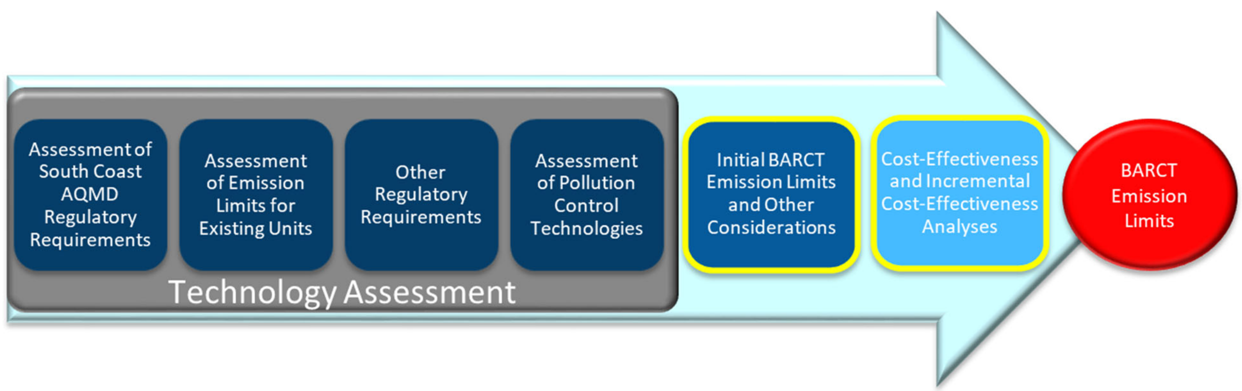
Under Health and Safety Code Section 40406, BARCT is defined as:

> "… an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

The BARCT assessment for this rule development consisted of a multi-step analysis. The first four steps represent the technology assessment. First, staff evaluated current South Coast AQMD regulatory requirements with an applicability to this rule development. Second, staff then assessed emission limits for existing units. Third, staff next surveyed other air districts and agencies outside of the South Coast AQMD's jurisdiction to identify emission limits that exist for similar equipment. In the final step of the technology assessment, staff assessed pollution control technologies to determine what degree of reduction could be achievable for the affected sources. Based on the technology assessment, initial emission limits and other considerations were proposed.

Once initial emission limits have been proposed, staff then calculated the cost-effectiveness of the proposals. The calculations consider the cost to meet the initial BARCT emission limit and the emission reductions that would occur from implementing technology that could meet the initial BARCT emission limit. An incremental cost-effectiveness analysis is conducted if multiple cost-effective control technology options are identified. Options are compared to determine costs of emission reductions. Based on the evaluation of the information, BARCT emission limits are recommended. See Figure 2-1 below for a graphical representation of the BARCT assessment process.

Figure 2.1 – BARCT Assessment Process



## BARCT ANALYSIS APPROACH

In this rulemaking effort, staff is considering the following proposals to be incorporated into the rule:

(1) Adding the use of enhanced monitoring and leak detection techniques
(2) Establishing emission limits for internal combustion engines used to operate wellhead pumps
(3) Establishing emission limits for stationary gas turbines using produced gas for fuel
(4) Requiring electrification or the use of cleaner engines for workover rigs

### (1) Adding the use of enhanced monitoring and leak detection techniques

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, Rule 1148.1(i)(1) requires the use of an appropriate analyzer calibrated with methane per U.S. EPA Reference Method 21 to inspect components and equipment regulated by the rule. Typically, the analyzer used is a Toxic Vapor Analyzer (TVA) (See Figure 2.2). A TVA is capable of measuring a variety of organic vapors using flame ionization detection (FID) technology and it provides a concentration value of the organic vapor.

Figure 2.2 – Example of a Toxic Vapor Analyzer

Other South Coast AQMD Rules also require the use of an appropriate analyzer calibrated with methane per U.S. EPA Reference Method 21 to conduct inspections including but not limited to: Rule 1149 – *Storage Tank and Pipeline Cleaning and Degassing*; Rule 1173 – *Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants*; Rule 1176 – *VOC Emissions from Wastewater Systems*; and Rule 1178 – *Further Reductions for VOC Emissions from Storage Tanks at Petroleum Facilities*.

In September 2023, Rule 1178 was amended to include optical gas imaging (OGI) inspections for equipment subject to the rule. In June 2024, Rule 463 was also amended to require OGI inspections.

- *Assessment of Emission Limits of Existing Units*

The use of OGI equipment does not have an emission limit relevant to this analysis. As such, no assessment of emission limits of existing units is required.

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that the use of enhanced monitoring techniques utilizing OGI was limited.

San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4409 – *Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities*, subsection 6.3, after June 30, 2024, requires that all leaks detected with the use of an OGI instrument shall be measured using U.S. EPA Reference Method 21 within two 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 the rule.[1]

Figure 2.3 – Example of an OGI camera

Under Colorado Air Quality Control Commission Regulation Number 7 – *Control of Emissions from Oil and Gas Emissions Operations*, the use of an OGI camera can be utilized as part of an approved leak detection and repair plan.[2] Leak detection thresholds are quantified using a TVA or equivalent device.

- *Assessment of Pollution Control Technologies*

OGI equipment does not control pollution directly but is a tool that can be used to identify emissions. As such, no assessment of pollution control technology is required for adding the use of enhanced monitoring and leak detection techniques. However, a discussion on current enhanced monitoring and leak detection technologies is included.

Optical Gas Imaging

An optical gas imaging camera uses infrared technology capable of visualizing vapors. OGI cameras have different detectors capable of visualizing a variety of gas wavelengths. VOC wavelengths are in the 3.2-3.4 micrometer waveband.

Figure 2.4 – OGI Camera Imaging

The cameras are widely used as a screening tool for leak detection purposes and have continuous monitoring capability.

[1] San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4409 – *Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities*, subsection 6.3: https://ww2.valleyair.org/media/z11dynbx/rule-4409.pdf, p. 4409-21, accessed on November 1, 2023.

[2] Colorado Air Quality Control Commission Regulation Number 7 – *Control of Emissions from Oil and Gas Emissions Operations*: https://drive.google.com/file/d/1P6pRmNYx5KwEK6qDReYFL11-K-URI33J/view, p. 36, accessed on November 1, 2023.

Handheld OGI cameras are used widely by leak detection service providers as well as facilities for periodic monitoring.

<u>Open Path Sensors</u>

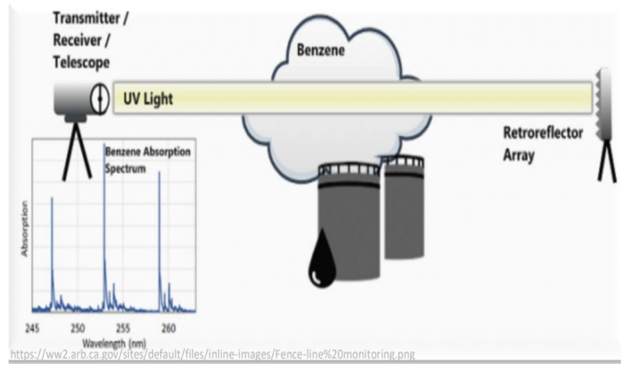



Figure 2.5 – Example of Open Path Technology

Open path detection devices emit beams that detect VOCs (See Figure 2.5). For VOC to be detected with an open path device, the VOCs must contact the beam. Open path detection devices can detect gas concentrations in the parts per billion range and from distances as far as 300 meters away from a source, with some models advertised as having a range of 1,000 meters. One open path device can cover multiple paths. Open path devices can detect small concentrations of VOC in the parts per billion by volume (ppbv) range and can also speciate VOC. A significant limitation to leak detection of these devices is the requirement for VOCs to contact the emitted beam. This provides a chance for VOCs to go undetected if travelling on a path that does not intercept the beam. Another drawback to open path detection is the dilution factor. VOCs originating from a tank may need to travel hundreds of feet before contacting the emitted beam. The concentration of VOC may dilute so significantly that VOCs are undetectable by the time the VOCs reach the emitted beam.

<u>Fixed Gas Sensors</u>

Figure 2.6 – Example of a Fixed Gas Sensor

Fixed gas sensors have the capability to continuously monitor for VOC emissions and are installed as fixed applications (See Figure 2.6). Concentrations of VOC detected with fixed gas sensors are in the parts per million by volume (ppmv) range depending on the sensor and have a maximum detection range of about 50-100 ppmv. Like open path devices, gas sensors can only detect emissions when VOCs contact the fixed sensor. Leaks from a source must be significant to be detected by a fixed gas sensor due to the dilution factor. According to one supplier, it is estimated that a leak with a concentration of 72,000 ppmv is detectable by a gas sensor 100 feet away. A leak with a concentration of 18,000 ppmv is detectable by a gas sensor 50 feet away.

**(2) Establishing emission limits for internal combustion engines used to operate wellhead pumps**

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, Rule 1148.1 does not have any emission limits for engines operated at facilities subject to this rule. However, other South Coast AQMD rules do regulate internal combustion engines. South Coast AQMD Rules 1110.2 – *Emissions from Gaseous- and Liquid-Fueled Engines* and

1470 – *Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines* regulate emissions from internal combustion engines that are rated greater than 50 bhp. In addition, stationary engines that are greater than 50 bhp are required to be permitted by the South Coast AQMD. Some engines, however, that are less than 50 bhp but are operated by facilities subject to the South Coast AQMD Regional Clean Air Incentives Market (RECLAIM) program are also subject to permitting requirements. Portable engines that are greater than 50 bhp are required to be either registered by the California Air Resources Board (CARB) through their Portable Equipment Registration Program (PERP) or permitted by the South Coast AQMD.

- *Assessment of Emission Limits of Existing Units*

Figure 2.7 – Example of an ICE

During the rule development process, staff visited multiple sites where internal combustion engines were observed to be operating wellhead pumps (See Figure 2.7). The sites were not part of the RECLAIM program. In general, these engines were rated under 50 bhp and were powered by produced gas from the individual sites. The engines were not observed to have any emission controls on their exhaust. As long as the supply of produced gas was available or as necessary, the engines were operated continuously 24 hours a day, 7 days a week. Because the observed engines were rated at less than 50 bhp, Rules 1110.2 and 1470 do not apply. Thus, the engines used to operate wellhead pumps generally do not have an emission limit unless the engine is rated greater than 50 bhp.

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that for rules that similarly regulate oil and gas production sites, engines are not included in their respective regulations. However, in their suite of rules, other regulatory agencies do regulate emissions from stationary internal combustion engines such as: BAAQMD Regulation 9 – *Inorganic Gaseous Pollutants*, Rule 8 – *Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines* and SJVAPCD Rule 4702 – *Internal Combustion Engines.*

- *Assessment of Pollution Control Technologies*

Application of Nonselective Catalytic Reduction Technology

During site visits, staff noted that the internal combustion engines observed were engines that are classified as rich-burn engines. Rich-burn engines operate at a higher concentration of fuel to air in its combustion chamber compared to lean-burn engines which operate at a higher concentration of air to fuel in its combustion chamber. With a higher concentration of fuel to air, rich-burn engines respond to varying loads more effectively compared to lean-burn engines. On oil field and gas production sites, the supply of produced gas to an engine can vary making the rich-burn engine one of choice and necessity.

Although no exhaust emission controls were observed on engines used to operate wellhead pumps, there exists commercially available air pollution control equipment that can be installed on rich-burn engines such that if operated properly can achieve emission reduction compliant to the NOx emission limit established in Rule 1110.2.

Figure 2.8 – Example of an NSCR Device

Nonselective Catalytic Reduction (NSCR) technology is applicable to all rich-burn engines and is a common control method for rich-burn engines (See Figure 2.8). The first wide scale application of NSCR technology occurred in the mid- to late-1970s, when 3-way NSCR catalysts were applied to motor vehicles with gasoline engines. Since then, this control method has found widespread use on stationary engines. Improved NSCR catalysts, called 3-way catalysts because CO, VOC, and NOx are simultaneously controlled, have been commercially available for stationary engines for over 20 years.

The NSCR catalyst promotes the chemical reduction of NOx in the presence of CO and VOC to produce oxygen and nitrogen. The 3-way NSCR catalyst also contains materials that promote the oxidation of VOC and CO to form carbon dioxide and water vapor. To control NOx, CO, and VOC simultaneously, 3-way catalysts must operate in a narrow air/fuel ratio band (15.9 to 16.1 for natural gas-fired engines) that is close to stoichiometric.

Removal efficiencies for a 3-way catalyst are greater than 90% for NOx, greater than 80% for CO, and greater than 50% for VOC. Greater efficiencies, below 10 parts per million NOx, are possible through use of an improved catalyst containing a greater concentration of active catalyst materials, use of a larger catalyst to increase residence time, or through use of a more precise air/fuel ratio controller.

NSCR catalysts are subject to masking, thermal sintering, and chemical poisoning. In addition, NSCR is not effective in reducing NOx if the CO and VOC concentrations are too low. NSCR is also not effective in reducing NOx if significant concentrations of oxygen are present. In this latter case, the CO and VOC in the exhaust will preferentially react with oxygen instead of the NOx. For this reason, NSCR is an effective NOx control method only for rich-burn engines.

When applying NSCR to an engine, care must be taken to ensure that the sulfur content of the fuel gas is not excessive. The sulfur content of pipeline-quality natural gas and LPG is very low, but some oil field gases and waste gases can contain high concentrations. Sulfur tends to collect on the catalyst, which causes deactivation. This is generally not a permanent condition and can be reversed by introducing higher temperature exhaust into the catalyst or simply by heating the catalyst. Even if deactivation is not a problem, the water content of the fuel gas must be limited when significant amounts of sulfur are present to avoid deterioration and degradation of the catalyst from sulfuric acid vapor.

In cases where an engine operates at idle for extended periods or is cyclically operated, attaining and maintaining the proper temperature may be difficult. In such cases, the catalyst system can be designed to maintain the proper temperature, or the catalyst can use materials that achieve high efficiencies at lower temperatures. For some cyclically operated engines, these design changes may be as simple as thermally insulating the exhaust pipe and catalyst. Most of these limitations can be eliminated or minimized by proper design and maintenance.

Electrification of All Engines

During site visits, staff observed that most wellhead pumps are electrically driven. However, on a few sites, some wellhead pumps were being powered by engines fueled by produced gas. Staff noted that on these few sites, the produced gas could not be routed offsite for further processing or collection. In order to maintain operation of the site, the operator could either vent the produced gas to the atmosphere, install a combustion device to flare it, install a boiler or heater to consume it, or utilize an internal combustion engine or a stationary turbine to produce power to run a wellhead pump. In the past, another option included potentially reinjecting the produced gas back into the oil formation; however, staff has learned that other regulatory agencies such as the City of Los Angeles Zoning Administrator severely restrict this practice and it is no longer common.

**(3) Establishing emission limits for stationary gas turbines using produced gas for fuel**

- *Assessment of Current South Coast AQMD Regulatory Requirements*

During the rule development process, staff visited multiple sites where stationary gas turbines were operated using process gas as their fuel source. Currently, Rule 1148.1 does not have an emission limit for turbines operated at facilities subject to this rule. However, for turbines that are rated at 0.3 MW and larger, South Coast AQMD Rule 1134 – *Emissions of Oxides of Nitrogen from Stationary Gas Turbines* applies.

- *Assessment of Emission Limits of Existing Units*

Rule 1134 limits NOx emissions from stationary gas turbines that are fueled by produced gas to 9 ppmv at 15% $O_2$ on a dry basis. For engines rated at less than 0.3 MW, there is currently no emission limit set by the South Coast AQMD.


Figure 2.9 – Example of a Stationary Gas Turbine

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that for rules that similarly regulate oil and gas production sites, stationary gas turbines are not included in their respective regulation. However, in their suite of rules, other regulatory agencies do regulate the emissions from stationary gas turbines engines such as: BAAQMD Regulation 9 – *Inorganic*

*Gaseous Pollutants*, Rule 9 – *Nitrogen Oxides Stationary Gas Turbines* and SJVAPCD Rule 4703 – *Stationary Gas Turbines*. These rules also exempt smaller turbines such as those used at oil and gas well production sites.

The CARB Distributed Generation (DG) Certification Regulation is available to smaller gas turbines that are exempt from air district permitting requirements. These units must demonstrate that they meet or exceed the following emission standards:

Table 2.1: DG Emission Standards

| Pollutant | Emission Standard (lb/MW-hr) |
|---|---|
| NOx | 0.07 |
| CO | 0.10 |
| VOCs | 0.02 |

- *Assessment of Pollution Control Technologies*

To control NOx emissions, Selective Catalytic Reduction (SCR) technology is often used. SCR is a commercially available air pollution control system used to reduce NOx emissions from stationary gas turbines. SCR technology injects ammonia into a turbine's exhaust. The exhaust is then passed through a fixed catalyst bed where NOx reacts with the ammonia and is converted into nitrogen. If CO and VOCs are also to be controlled, then an oxidation catalyst is added to the exhaust stream typically upstream of the SCR. Catalyst efficiency relies on good dispersion and mixing. Typical conversion efficiencies for SCR systems range between 90 – 95% for NOx.

Dry Low NOx controls NOx by combusting gas at lower temperatures using a lean premixed combustion. An advanced control system in also utilized. Low NOx levels are achieved as the process requires less fuel and air resulting in lower combustion temperatures.

**(4) Requiring electrification or the use of cleaner engines for workover rigs**

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, the electrification or the use of cleaner engines for workover rigs is not required by Rule 1148.1. Other South Coast AQMD rules do not mandate the use of electrified or cleaner engines. However, Rule 1148.2 requires the operator of a workover rig where the engine does not meet a minimum Tier 4 Final emissions standards of Title 40 of the Code of Federal Regulations Part 1039 Subpart B, Section 1039.101, Table 1 and the engine is not powered by a non-combustion source, to notify the Executive Officer no more than 10 calendar days and no less than 24 hours prior to the use of the workover rig on either an onshore oil or gas well, or an injection well. This engine standard shall also apply to any engine that connects to, and assists, the workover rig with any well activity.

- *Assessment of Emission Limits of Existing Units*

Typically, workover rigs use engines that are considered to be off-road compression-ignition diesel engines and are registered through CARB's PERP. Depending on the age and the rated bhp of the engine, an engine is assigned to a Tier category. Based on the tier level, emission limits vary. For example, a 2008 engine rated between 75 – 100 bhp falls under the Tier 3 category and it has a NOx emission limit of 3.5 g/bhp-hr (~ 234 ppmv at 15% $O_2$). In comparison, a 2015 engine rated similarly falls under the Tier 4 Final category and it has a NOx emission limit of 0.14 g/bhp-hr (~ 9 ppmv at 15% $O_2$). It should be noted that engines which are integrated with the propulsion of the rig itself is not included in CARB's PERP.

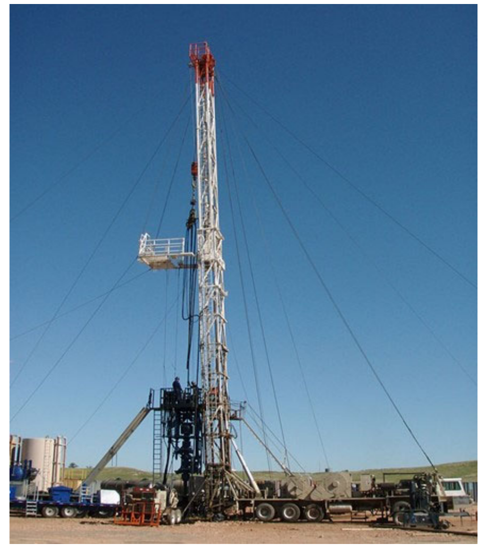


Figure 2.10 – A Workover Rig in Operation

- *Other Regulatory Requirements*

U.S. EPA has developed Tier 4 standards for nonroad diesel engines to reduce emissions. Exhaust emissions from Tier 4 engines decrease emissions from older engines by more than 90%.[3] The Tier 4 standards took effect for new engines beginning in 2008 and were fully phased in for most diesel engines by 2014. Thus, new engines manufactured after 2008 are required to meet the applicable standard effective when the engine is built. Staff has noted that engines used on workover rigs range between 175 ≤ hp < 750 and widely range in age. Staff has observed during site visits that only some engines used on workover rigs are currently required to meet Tier 4 standards.

The Tier 4 emission standards are provided in the following table.

[3] U.S. EPA, Summary and Analysis of Comments: Control of Emissions from Nonroad Diesel Engines, May 2004: https://nepis.epa.gov/Exe/ZyPDF.cgi/P10003DS.PDF?Dockey=P10003DS.PDF, accessed on November 2, 2023.

Table 2.2 – Tier 4 Final Emission Standards in grams per horsepower-hour (g/hp-hr)

| Rated Power | First Year that Standards Apply | PM | NOx |
|---|---|---|---|
| hp < 25 | 2008 | 0.30 | - |
| 25 ≤ hp < 75 | 2013 | 0.02 | 3.5* |
| 75 ≤ hp 175 | 2012-2013 | 0.01 | 0.30 |
| 175 ≤ hp < 750 | 2011-2013 | 0.01 | 0.30 |
| hp ≥ 750 | 2011-2014<br>2015 | 0.075<br>0.02/0.03** | 2.6/0.50†<br>050†† |

* The 3.5 g/hp-hr standard includes both NOx and nonmethane hydrocarbons
† The 0.05 g/hp-hr standard applies to gensets over 1200 hp
** The 0.02 g/hp-hr standard applies to gensets; the 0.03 g/hp-hr standard applies to other engines
†† Applies to all gensets only.

- *Assessment of Pollution Control Technologies*

SCR Technology

To achieve Tier 4 Final NOx emission levels, engine manufacturers will use small-scaled SCR units on the exhaust of these engines. SCR technology injects ammonia into a turbine's exhaust. The exhaust is then passed through a fixed catalyst bed where NOx reacts with the ammonia and is converted into nitrogen. If CO and VOCs are also to be controlled, then an oxidation catalyst is added to the exhaust stream typically upstream of the SCR. Catalyst efficiency relies on good dispersion and mixing. Typical conversion efficiencies for SCR systems range between 90 – 95% for NOx.

Electrification of Engines Used for Workover Rigs

Staff observed the use of an electrified workover rig at two different sites and is aware of another electrified workover rig that had once been installed and operated at another site. At the two sites where there was an electrified rig, staff noted that the units were not capable of leaving the site and were confined to move on a fixed rail system within the facility. In addition, each site had been retrofitted with a robust electrical substation to meet the electrical demand required by a workover rig. The fixed rail system would also be especially challenging for oil and gas well sites that are difficult to access due to terrain and location. See Figure 2.11 for photos on an electrically powered drilling/workover rig.

Figure 2.11 – Photo on left shows electrified drilling/workover rig and photo on right shows inside view. Note that this drilling/workover rig is on a rail and can only be used at this specific site

# CHAPTER 3: PROPOSED AMENDMENTS TO RULE 1148.1

## INTRODUCTION

Staff participated in multiple meetings with WCWLB and SLA community residents, acknowledged the CERP, conducted multiple site visits to oil and gas production sites, conducted a BARCT assessment, and presented our findings in a public process. The following proposals address the concerns raised in these communities.

## PROPOSED AMENDMENTS TO RULE 1148.1

### Subdivision (c) – Definitions

The definitions listed below are being revised or added due to the proposed amendments to Rule 1148.1:

- **COMPONENT** – The definition is updated to include the wellhead and stuffing box as recognized components.

- **ENGINE** – During the rule development process, staff noted that produced gas was being utilized to power engines used to operate wellheads. Staff has added this definition as part of introducing emission limits onto engines that are powered and consuming produced gas from oil field and production sites. Staff referenced South Coast AQMD Rule 1110.2 for development of this definition.

- **FUEL CELL** – The definition is added to recognize the technology as an alternate to engines. U.S. EPA describes fuel cells as follows. A fuel cell is an electrochemical device similar to a battery. While both batteries and fuel cells generate power through an internal chemical reaction, a fuel cell differs from a battery in that it uses an external supply that continuously replenishes the reactants in the fuel cell. A battery, on the other hand, has a fixed internal supply of reactants. The fuel cell can supply power continuously as long as the reactants are replenished, while the battery can only generate limited power before it must be recharged or replaced.[4]

- **GAS HANDLING** – Staff discussed the intent of gas handling operations within the Applicability section of the rule and discovered a potential misunderstanding of using the term "processed gas" instead of "produced gas." Staff updated rule language to state "produced gas" in the first sentence of the Applicability section and created a definition for "gas handling" to further clarify the intent of this rule.

- **NEUTRALIZING AGENTS** – Staff has added this definition as part the proposal to remove the use of odorants from oil and gas production sites. AB 617 communities have expressed concern that odorants may be masking chemicals that can be harmful to the environment and to members of the public. Staff is making a distinction between neutralizing agents and odorants, which are specifically designed to mask an odor.

[4] U.S. EPA Auxiliary and Supplemental Power Fact Sheet: Fuel Cells: https://www.epa.gov/sites/default/files/2019-08/documents/fuel_cells_fact_sheet_p1004xfm.pdf, accessed on June14, 2023.

- **ODORANT** – Staff has added this definition as part the proposal to remove the use of odorants from oil and gas production sites. AB 617 communities have expressed concern that odorants may be masking chemicals that can be harmful to the environment and to members of the public.

- **OPTICAL GAS IMAGING DEVICE** – Staff has added this definition as part of introducing enhanced monitoring technology into the rule. Staff referenced South Coast AQMD Rule 1178 for development of this definition.

- **STATIONARY GAS TURBINE** – During the rule development process, staff noted that produced gas was being utilized to power stationary gas turbines that produce electricity to either power the site or supply the local electrical power grid. Staff has added this definition as part of introducing emission limits onto turbines that are powered and consuming produced gas from oil field and production sites. Staff referenced South Coast AQMD Rule 1134 for development of this definition.

- **TIER 4 FINAL ENGINE** – U.S. EPA established Tier 4 Final standards for nonroad diesel engines that reduce emissions by integrating engine and fuel controls as a system. Exhaust emissions of PM and NOx from these engines will decrease by more than 90%. These standards are achieved through the use of advanced exhaust gas after-treatment technologies such as urea-selective catalyst reduction (SCR) catalysts for NOx control, and diesel particulate filters (DPFs) for PM control. The use of ultra-low sulfur diesel (ULSD) fuel with a maximum sulfur content of 15 ppmv or less is also generally required.

- **VISIBLE VAPORS** – Staff has added this definition as part of introducing enhanced monitoring technology into the rule. Staff referenced South Coast AQMD Rule 1178 for development of this definition.

- **WORKOVER RIG** – Staff has added this definition to describe what a workover rig is. Staff developed this definition by researching various oil field industry websites that listed workover rigs, and from first-hand observations of workover rigs used in the local oil field production facilities.

**Subdivision (d) – Requirements**

The requirements listed below are being revised or added due to the proposed amendments to Rule 1148.1.

- Paragraphs (d)(7) and (d)(9) – The word “business” was removed from these paragraphs for consistency. The oil and gas production facilities operate 24 hours a day and 7 days a week. Therefore, there is no need to distinguish a business day from a regular day.

- Paragraph (d)(13) – During the amendment to Rule 1148.2 – *Notification and Reporting Requirements for Oil and Gas Wells and Chemical Suppliers*, concerns were raised about signs installed at oil field and production sites. AB 617 stakeholders requested that instructions be provided on how to make odor complaints and electronically access information on well activities. Staff referenced South Coast AQMD Rule 1460 –*Control of Particulate Emissions from Metal Recycling and Shredding Operations* for development of this requirement. Figure 3.1 shows a typical sign for an oil and gas facility.


Figure 3.1 - Example of Signage Prior to Amendment

- Paragraph (d)(14) – Staff has added this requirement as part of introducing enhanced monitoring technology using an OGI camera as part of the inspection process.

- Paragraph (d)(15) – Staff has added a NOx emission limit to engines that are powered by produced gas. During site visits, staff discovered engines being used to process produced gas from oil field sites. These engines were observed in the operation of wellheads and similar production equipment.

  Generally, produced gas can be collected and routed from an oil field to another location offsite to be further processed into a usable stream. For example, some produced gas can be sent to supply the Southern California Gas Company or similar company. Alternatively, produced gas can be collected from an oil field and used onsite to power combustion equipment such as a stationary gas turbine, an engine. If the gas cannot be sent offsite or used to power combustion equipment, then it is vented to a flare.

  In the case of engines using produced gas, staff discovered that these engines were typically rated at less than 50 bhp. By using engines that are rated less than 50 bhp, an engine is not subject to the emission limits established in Rule 1110.2. Rule 1110.2 applies only to engines rated greater than 50 bhp. In addition, the South Coast AQMD does not require a permit to operate for an engine rated less than 50 bhp unless the engine is located at a facility subject to the South Coast AQMD RECLAIM program. Rule 1110.2 may be amended in future rulemaking activity to include engines that are rated at less than 50 bhp. However, since these engines are currently operated at oil and gas production facilities, staff has included them under this rule to address air quality concerns and potential health impacts to the community.

Staff is concerned that this type of engine is an uncontrolled source of emissions. Staff visited sites where these engines were observed in operation and noted that these engines can operate continuously 24 hours a day, 7 days a week based on produced gas supply and/or electrical demand. Upon observing these engines, staff did not see any emission control devices on them. Staff also has observed that multiple engines can operate within close proximity to each other where although a single engine may be rated at less than 50 bhp, the aggregate horsepower of all of the engines on the site exceeds 50 bhp. In addition, staff has observed that some of these engines are located within less than 1000 feet of sensitive receptors such as residences and other dwellings.

During the third working group meeting that was held on December 14, 2023, staff received a comment inquiring if the produced gas could be reinjected back into the ground. Staff researched the inquiry and held a meeting with an LA City Planning employee and discovered that reinjecting gas back into the ground is discouraged due to safety concerns of having gas stored below residential neighborhoods. Additionally, LA City prefers to have the produced gas used in microturbines that meet certain emission standards. Staff also recognizes that CalGEM already regulates injection wells, including underground gas storage.

To address concerns over these engines, staff is proposing that engines meet the NOx emission limit applicable to engines regulated by Rule 1110.2 irrespective of rating. Currently, the NOx emission limit for Rule 1110.2 engines is established at 11 ppmv at 15% O2, on a dry basis with limited exceptions. To phase in compliance with this proposal, staff proposes a two-year implementation period from the date of the rule amendment to be reasonable amount of time for operators of such equipment to either retrofit existing equipment, install new equipment, or find alternative solutions.

- Paragraph (d)(16) – Staff has added a NOx emission limit to stationary turbines that are powered by produced gas. During site visits, staff observed stationary turbines being used to process produced gas from oil field sites generating electricity that was either being used onsite or was exported to the electrical power grid. For stationary turbines rated greater than 0.3 MW, Rule 1134 applies; however, for units rated less than 0.3 MW, no emission limits are applicable. Staff has generally observed microturbines that are rated at 65 kW (0.065 MW) at various oil and gas production sites with some larger ones rated at 200 kW (0.2 MW).

  To address concerns over turbines that are not subject to Rule 1134, staff is proposing that all stationary turbines meet the NOx emission limit applicable to stationary turbines as regulated by Rule 1134 irrespective of rating. Staff considers that the amount of microturbines installed and operated at oil and gas production sites to be a small number. Thus, rather than amend Rule 1134, staff is including this subset of turbines in this rule. Currently, the NOx emission limit for Rule 1134 turbines fueled by produced gas engines is established at 9 ppmv at 15% O2, on a dry basis with limited exceptions. To phase in compliance with this proposal, staff proposes a two-year implementation period from the date of the rule amendment to be reasonable amount of time for operators of such equipment to either retrofit existing equipment, install new equipment, or find alternative solutions.

- Paragraph (d)(17) – Staff is proposing that workover rigs used at oil and gas well sites be equipped with at least a Tier 4 Final engine. Based on AB 617 community concerns over emissions from diesel workover rigs, staff conducted site visits and also researched the potential emission reductions and feasibility of requiring electrified workover rigs. Part of the research included conducting a cost-effectiveness analysis. The results indicated that electrifying the workover rigs would exceed the cost-effectiveness threshold and take many more years to implement due to lack of infrastructure that would be needed.

  To address concerns over emissions from workover rigs, staff is proposing requiring all workover rigs to meet Tier 4 Final standards. While conducting research on this proposal staff found that the emission reductions on a Tier 4 Final engine are significant compared to Tier 2 level engines and this requirement was found to be cost-effective. Staff is proposing a three-year implementation period from the date of this rule amendment to either upgrade or replace their fleet of workover rigs. In addition, staff has found that some oil and gas operators have already upgraded part of their workover fleet to meet Tier 4 Final engine standards.

- Paragraph (d)(18) – Staff is proposing to ban the use of odorants, specifically odorants that are used to mask another chemical substance's smell. AB 617 community stakeholders have expressed concerns about the use of odorants and the potential exposure to unknown chemicals.

  Staff researched and found that some oil and gas production site operators are using odorants with strong fruit fragrances like guava or cherry. These operators have attempted to mask petroleum and oily-type odors with these odorants but it has led to several public nuisance violations with complaints of rotten fruit-type odors mixed with petroleum odors. Some complainants described having headaches. Mistrust has been created among community members due to the lack of knowledge about an odorant's chemicals and the substance that is being masked with the odorant. Odorants are generally composed of hydrocarbons such as alcohols and glycols but may also contain phenols or aromatics. These chemicals contribute to ozone formation and public nuisance complaints. They may also have health impacts depending on the type and quantity of the odorant substance.

  Paragraph (d)(19) - Staff recognizes that oil and gas operators may use neutralizing agents as an alternative to odorants for maintenance of their wells, including during the removal of well tubing as the well tubing may have its own odors. Neutralizing agents work to "knock out" or eliminate the odors, as opposed to masking the odors. Staff has proposed to allow the continued use of neutralizing agents that do not contain any toxics listed in Rule 1401 in quantities greater than 0.1% by weight. Staff also suggests that neutralizing agents be applied in liquid or droplet form and should not be atomized. If a neutralizing agent were atomized into the air, these chemicals may create odors. Staff has added definitions to clarify the differences in this requirement by adding the word 'odorant' and the word 'neutralizing agent' to the list of definitions.

It should be noted that this requirement does not affect the use of mercaptans or other chemicals that are purposefully injected into specific gas lines for safety purposes such as for detecting a gas leak in gas lines that are used, for example, in sales.

- Paragraph (d)(20) – Staff is proposing to require operators to submit a notification within twenty-four hours of discovering a leak greater than 25,000 ppmv VOC. Notifications were requested by community stakeholders that are interested in knowing when a leak has been found so that they can choose their next course of action.

  Operators will report leaks using the existing portal that is currently being used to submit notifications under Rule 1148.2. Interested parties that have signed up to receive Rule 1148.2 notifications will also receive notifications of reported leaks. The proposed data to be submitted will include facility information, leak concentration, date of discovery, and status of any repairs.

**Subdivision (e) – Operator Inspection Requirements**

- Paragraph (e)(6) – Staff has added an enhanced leak detection requirement using an OGI camera. The requirement has been modeled after the OGI requirement found in SJVAPCD Rule 4409. Comparing the use of an OGI camera with the use of a TVA, staff recognizes differences between the two applications. The OGI camera is expected to be used as a screening tool. With its current technological capabilities, an OGI camera cannot quantify an emission concentration whereas a TVA can report an emission in a concentration value. However, an OGI camera can scan more components quicker than a TVA, which can only inspect one component at a time. Used together, this technology is expected to give an operator the ability to identify leaks faster and to repair them sooner, compared with not using both in unison.

  Staff has added two options that operators can choose from when conducting their monthly OGI inspections and repairs under (e)(6)(B)(ii). If only using an OGI camera and quantification through use of a TVA is not initially made, operators will be required to repair any discovered leaks within twenty-four hours of discovery. Additionally, if any leak cannot be repaired within twenty-four hours, then the operator will be required to quantify the leak within forty-eight hours of leak discovery and to follow Rule 1173 subdivision (g) ~~the Repair Period Table in Rule 1173~~. Note the repair period timing pursuant to Rule 1173 starts once quantification is made and the concentration of the leak is known.

  If using both an OGI camera and an appropriate analyzer, operators will be required to repair any discovered quantified leaks within the time allowed pursuant to Rule 1173 subdivision (g)

~~the Repair Period Table in Rule 1173~~. In either option where quantification is needed, an appropriate analyzer that complies with paragraph (j)(1) shall be used. The intent of these two options is to give operators flexibility in conducting their monthly inspections. Staff recognizes that operators may not have ready access to a TVA; so, if an operator uses an OGI camera, identifies a leak, and repairs the leak below an OGI visible threshold, rather than wait for a TVA, then staff encourages a repair sooner than later.

**Subdivision (i) – Testing Requirements**

New subdivision (i) was added to demonstrate compliance with emission limits proposed in the amendment to the rule.

- Paragraph (i)(1) – Staff added a source testing requirement for engines that use produced gas as a fuel source in order to demonstrate compliance with its emission limit. Prior to this amendment, many engines that fell under this category were rated under 50 bhp and no testing requirement was in place. Although these engines may be considered small, they can operate 24 hours a day, 7 days a week and cumulatively, the amount of emissions can be significant.

- Paragraph (i)(2) – Staff added a source testing requirement for stationary turbines that use produced gas as a fuel source in order to demonstrate compliance with its emission limit. Although this provision is identical to the provision in paragraph (i)(1), it is included to distinguish turbines from engines. Specifically, an exemption from source testing is provided in paragraph (k)(5) if the turbine is certified through CARB's Distributed Generation program. No similar program is available for engines using produced gas.

**Subdivision (j) – Test Methods**

- Paragraph (j)(6) – Since emission limits for equipment have been included in this amendment, staff is adding that any source testing be completed per South Coast AQMD Method 100.1.

**Subdivision (k) – Exemptions**

- Paragraph (k)(5) – Staff added an exemption for a stationary turbine that has been certified by CARB Distributed Generation Certification program such that no source test of the engine shall be required. For engines that have not been certified as such, they will be required to demonstrate compliance via a periodic source test.

**Other Revisions**

- Since the 2015 Amendment to the rule, the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) has been replaced by the California Geologic Energy Management (GEM) Division. Reference to DOGGR has been replaced with GEM.

- The name of the agency such as AQMD or District has been replaced by the South Coast AQMD.

- Staff updated references within the rule to account for amendments and deleted obsolete wording and provisions.

- Staff considered revisions to paragraph (d)(8) but believes that the current language allows flexibility to address leaks from equipment associated with well heads and well cellars. For example, produced gas from a tank that has been blocked-in but contains inventory from oil and gas field production activities shall be routed to a system handling gas for fuel, sale, or underground injection or to a control device so as to avoid leaks.

# CHAPTER 4: IMPACT ASSESSMENTS

## INTRODUCTION

Impact assessments were conducted as part of PAR 1148.1 rule development to assess the environmental and socioeconomic implications of PAR 1148.1. These impact assessments include emission reduction calculations, cost-effectiveness and incremental cost-effectiveness analyses, a socioeconomic assessment, and a California Environmental Quality Act (CEQA) analysis. Staff prepared draft findings and a comparative analysis pursuant to Health and Safety Code Sections 40727 and 40727.2, respectively.

## EMISSION REDUCTIONS

PAR 1148.1 will establish more stringent control and monitoring requirements at oil and gas production sites that will result in emission reductions.

*OGI Monitoring*

Staff is proposing the monthly use of OGI as a tool to find leaks from equipment regulated by this rule. By using OGI, leaks can be discovered and repaired sooner than through current inspection frequency and technique. Emission reductions from this proposal were calculated based on estimated baseline emissions and assumed one major leak per year from 10% of the 330 affected facilities. Staff used a leak rate of 200 lbs/day of VOC for each assumed major leak rate. This assumed leak rate is 98% smaller than the leak rate used in Rule 1178 but is expected to be consistent with the type of facilities regulated by this rule. Rule 1178 estimated approximately 8,000 lbs/day of emission losses based on U.S. EPA's 2016 Control Technology Guidelines for Oil and Gas Industry.[5]

Based on the current quarterly inspection frequency, staff assumes that an undiscovered leak occurs at a midpoint between inspections of 45 days. If the inspection frequency is increased to monthly, then staff assumes that an undiscovered leak occurs at a midpoint of 15 days. Comparing the current quarterly inspection frequency using the TVA to the proposed monthly frequency using OGI equipment, staff predicts that a potential leak may be discovered and repaired approximately 30 days sooner, a difference between 45 and 15 days.

To establish a baseline rate of potential emission, staff performed the following calculation:

- One leak per year from 10% of 330 affected facilities
- A leak rate of 200 lbs/day of VOC
- 45 days before a leak is identified

[5] South Coast AQMD Rule 1178 – Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1178/par-1178-draft-staff-report--final.pdf, p. 4-2, accessed on September 19, 2023.

- Calculation – (1 leak/yr) x (33 facilities) x (200 lbs VOC/day) x (45 days) x (1 yr/365 day) x (1 ton/2000 lb) = 0.40 ton VOC/day
- Using these assumptions, a potential baseline of 0.40 ton per day of VOC is attributable to Rule 1148.1 related equipment.

With OGI monthly inspections, staff anticipates a reduction in VOC emissions compared to the baseline. To determine the reduction, staff performed the following calculation:

- One leak per year from 10% of 330 affected facilities
- A leak rate of 200 lbs/day of VOC
- Discovery of a leak 30 days sooner
- Calculation – (1 leak/yr) x (33 facilities) x (200 lbs VOC/day) x (30 days) x (1 yr/365 day) x (1 ton/2000 lbs) = 0.27 ton VOC/day
- Using these assumptions, a potential reduction of 0.27 ton per day of VOC is attributable to OGI monthly inspections.

*Fenceline Monitoring*

<u>Stationary Gas Sensors</u>

Staff researched different types of fenceline monitoring systems and found that several oil and gas facilities had stationary gas sensors installed, primarily as a trial run for data collection. Staff found that that stationary gas sensors detect the targeted gas/emission such as VOCs once it makes contact with its sensor. During the research of fenceline monitors staff found that the number of sensors needed at each site varied depending on the size and terrain.

To determine potential emission reductions through fenceline monitoring using stationary gas sensors, staff used a similar approach to that used for OGI monitoring. In this case, since stationary monitors operate continuously, the emission reduction is credited as saving 45 days of undiscovered emissions. To quantify the reduction, staff performed the following calculation:

- One leak per year from 10% of 330 affected facilities
- A leak rate of 200 lbs/day of VOC
- 45 days of a leak that was identified
- Calculation – (1 leak/yr) x (33 facilities) x (200 lbs VOC/day) x (45 days) x (1 yr/365 day) x (1 ton/2000 lbs) = 0.40 ton VOC/day
- Using these assumptions, a potential reduction of 0.40 ton per day of VOC is attributable to stationary gas sensors.

<u>Open Path Sensors</u>

As an alternative to stationary gas sensors staff researched open path sensors and found that they use a transmitter to transmit a beam to a reflector that sends the beam back. Detection of a targeted gas/emission such as VOCs is made when it makes contact with the beam. Staff did not find any oil and gas production sites using open path sensors but included this as an option. Since open path sensors operate continuously like stationary gas sensors, a potential emission reduction equivalent of 0.40 ton per day of VOC would be expected. See calculation performed in the previous section for additional details.

*Engines Powered by Produced Gas*

Staff is proposing requiring facilities that use their produced gas to power engines that drive oil producing wells to meet a NOx emission standard of 11 ppmv @ 15% $O_2$ on a dry basis. This emission limit was obtained from South Coast AQMD Rule 1110.2 Table 2 for stationary engines. Emission reductions from this proposal were calculated based on the assumption that an unregulated engine used in this service has equivalent emissions of a spark ignition engine.[6] The reason that staff assumed a spark ignition engine is that these engines were powered by produced gas versus diesel as with typical compression ignition engines. With the proposed exhaust emission controls using a 3-way catalyst with an air-to-fuel ratio control, staff expects a reduction in NOx emissions of approximately 90% based on current technology performance of a 3-way catalyst.

To determine potential reductions in NOx emissions through the installation of exhaust emission controls, staff performed the following calculation:

- Uncontrolled emission factor for spark ignition engine of 1.5 g/hp-hr NOx (CARB reference emission data)
- Engine rated at 50 bhp
- Engine operates continuously: 24 hours, 365 days
- 90% reduction efficiency for catalyst system
- Calculation – (90% reduction) x (1.5 g/hp-hr) x (50 hp) x (365 days/yr) x (24 hr /day) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.0018 ton NOx/day
- Using these assumptions, a potential reduction of 0.0018 ton per day of NOx is attributable to the installation of exhaust emission controls

It should be noted that this calculation is on a per engine basis and the total emissions reduced will vary by the actual number of engines retrofitted and used at oil and gas production sites.

*Microturbines Powered by Produced Gas*

As an alternative to routing produced gas to engines, staff acknowledges that stationary gas turbines can also use produced gas resulting in a similar NOx emission reduction of approximately 90%. Staff is proposing that the NOx emission limit for microturbines be 9 ppmv @ 15% $O_2$ on a dry basis, which was obtained from Table 1 from Rule 1134 for stationary gas turbines. Emission

[6] California Air Resources Board – PERP Regulation : https://ww2.arb.ca.gov/sites/default/files/2020-03/PERP_Reg_12.5.18R.pdf, p. 21, accessed on November 1, 2023.

reductions from this proposal were calculated based on the assumption that one microturbine would replace three unregulated engines with equivalent emissions of spark ignition engines, as referenced above in the “Engines Powered by Produced Gas” section. Staff selected this ratio as representative of the amount of gas needed to sustain operation of a small microturbine relative to the amount of gas needed to sustain operation of an engine.

To determine potential reductions in NOx emissions through the installation of a microturbine replacing engines operating on produced gas, staff performed the following calculation:

- Uncontrolled emission factor for spark ignition engine of 1.5 g/hp-hr NOx (CARB reference emission data)
- Engines rated at 50 bhp (3 engines = 150 hp capacity)
- Engine operates continuously: 24 hours, 365 days
- Emission factor for a microturbine of 0.16 g/hp-hr (from manufacturer datasheet)
- Calculation – (1.5 g/hp-hr – 0.16 g/hp-hr) x (150 hp) x (365 days/yr) x (24 hr /day) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.005 ton NOx/day
- Using these assumptions, a potential reduction of 0.005 ton per day of NOx is attributable to the installation of one microturbine in lieu of three engines

It should be noted that this calculation is on a per microturbine basis and the total emissions reduced will vary by the actual number of microturbines installed and used at oil and gas production sites.

*Use of Tier 4 Final Workover Rigs*

Staff is proposing that workover rigs be powered by engines that are at least rated as Tier 4 Final. By requiring the use of Tier 4 Final engines on workover rigs, staff expects a significant reduction in emissions whenever the use of workover rigs is required. Staff assumed that the emissions from current workover rigs to be at Tier 2 levels. Staff also assumed that a workover rig is required four times per year at each site, is used four days per week, and eight hours per day. Workover rig engine size will vary. Staff assumed a rating of 600 hp to be representative of a typical engine. As noted previously, staff identified that there are approximately three hundred and thirty sites. To service these sites, staff estimated that approximately 40 rigs may be needed to cover potential demand.

To determine potential reductions in NOx emissions through the requirement of using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig, staff performed the following calculation:

- Tier 2 NOx emission factor of 4.5 g/bhp-hr
- Tier 4 Final NOx emission factor of 0.30 g/bhp-hr
- Approximately 40 rigs may be needed
- Operation of a rig is 4 days per week, 8 hours per day

- Typical engine size is 600 bhp
- Calculation – (4.5 g/hp-hr – 0.30 g/hp-hr) x (40 rigs) x (600 hp) x (8 hrs/day) x (4 days/week) x (52 weeks/yr) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.51 ton NOx/day
- Using these assumptions, a potential reduction of 0.51 tons per day of NOx is attributable to the requirement of using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig

*Electrification of Workover Rigs*

Staff researched the feasibility of requiring oil and gas production facilities to use electrified workover rigs instead of workover rigs equipped with diesel engines. During the rule development process, staff visited multiple oil and gas production sites and spoke to industry representatives and vendors. From these discussions and interaction, staff was made aware that the use of an electrically powered drilling/workover rig was only available at two sites. Staff visited these sites and found that these two sites were unique in that each had dedicated infrastructure installed to meet the electrical demands of these electrified drilling/workover rigs. Staff noted that these electrified drilling/workover rigs were designed to only operate at their respective sites and were not mobile.

To determine potential reductions in NOx emissions through the use of an electrified rig, staff performed a calculation similar to one comparing using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig. In this case, however, an electrified rig is assumed to emit zero NOx emissions.

- Tier 2 NOx emission factor of 4.5 g/bhp-hr
- Approximately 40 rigs may be needed
- Operation of a rig is 4 days per week, 8 hours per day
- Typical engine size is 600 bhp
- Calculation – (4.5 g/hp-hr) x (40 rigs) x (600 hp) x (8 hrs/day) x (4 days/week) x (52 weeks/yr) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.54 ton NOx/day
- Using these assumptions, a potential reduction of 0.54 ton per day of NOx is attributable to the requirement of using an electrified rig versus a rig equipped with Tier 2 engines

*Elimination of Odorants*

Due to concerns raised by stakeholders, staff proposes to eliminate the use of odorants. Although some odorants may contain VOC material, the overall reduction in VOC emissions associated with this activity is not expected to be significant.

*Improved Signage*

By producing and installing new signs at oil and gas production sites, some additional emission reductions may be generated, but these are expected to be one-time occurrences and are not expected to be significant.

## COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The cost-effectiveness of a control is measured in terms of the control cost in dollars per ton of air pollutant reduced. The costs for the control technology include purchasing, installation, operation, maintenance, and permitting. Emission reductions were calculated for each requirement and based on estimated baseline emissions. The 2022 AQMP established a cost-effectiveness threshold of $36,000 per ton of VOC reduced. A cost-effectiveness that is greater than the threshold of $36,000 per ton of VOC reduced requires additional analysis and a hearing before the Governing Board on costs. The 2022 AQMD also established a cost-effectiveness threshold of $325,000 per ton of NOx reduced. A cost-effectiveness that is greater than the threshold of $325,000 per ton of NOx reduced would also require additional analysis and a hearing before the Governing Board on costs.

The cost-effectiveness is estimated based on the present value of the retrofit cost, which was calculated according to the capital cost (initial one-time equipment and installation costs) plus the annual operating cost (recurring expenses over the useful life of the control equipment multiplied by a present worth factor).

Cost-Effectiveness (CE) = Present Worth Value (PWV) / Emission Reduction (ER)

PWV = Total Install Cost (TIC) + Present Worth Factor (PWF) x Annual Cost (AC)

Capital costs are one-time costs that cover the components required to assemble a project. Annual costs are any recurring costs required to operate equipment. Costs were obtained for OGI monitoring, retrofitting an existing engine powered by produced gas to drive a well, microturbines powered by produced gas, Tier 4 Final equipped workover rigs, and electrification of workover rigs.

*OGI Monitoring*

Staff is proposing the monthly use of OGI equipment as a tool to find leaks from equipment regulated by this rule. Costs for this proposal were obtained from vendors and facilities. Some oil and gas companies already use an OGI camera and staff was able to obtain further cost information such as maintenance and labor. In addition, South Coast AQMD retains OGI cameras, and training and maintenance cost information was available.

The following information was used to calculate the cost-effectiveness of purchasing and using an OGI camera:

- Number of oil and gas companies to be at approximately 80
- Cost of an OGI camera = $120,000 with a 10-year life span
- Annual maintenance = $1000
- Training = $1,000 every two years ($500 per year)
- In-House labor 1 person working 8 hours/day at $50/hr = $400/day
- Monthly inspections = 12/year
- Emission reduction based on analysis conducted previously = 0.27 tpd VOC

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = $120,000 x 80 cameras = $9,600,000
- AC = $1000 [maintenance] + $500 [training] + (1 person x 8 hr/day x $50/hr x 12 inspections/yr) [labor] = $6300 per OGI camera or $504,000 for 80 cameras
- PWV = $9,600,000 + 8.111 x $540,000 = $13,688,000
- ER = (0.27 tpd VOC) x (365 day/yr) x (10 years) = 990 tons VOC
- CE = $13,688,000 / 990 tons VOC reduced = $13,800/ton VOC reduced

Based on these assumptions, the cost-effectiveness for requiring monthly inspections using OGI cameras is calculated to be $13,800/ton VOC reduced.

*Fenceline Monitoring*

Stationary Gas Sensors

As an alternative to OGI cameras, staff researched the use of stationary gas sensors for the monitoring of VOCs. Costs used in this analysis were obtained from oil and gas facilities that have already installed stationary gas sensors.

The following information was used to calculate the cost-effectiveness of purchasing and installing fenceline monitoring equipment:

- Number of oil and gas sites is approximately 330
- Cost of each sensor = $3,115
- Number of sensors at a site = 14
- Installation cost of $30,000

- Estimated life span of 10 years
- Annual maintenance = $10,000
- Emission reduction based on analysis conducted previously = 0.40 tpd VOC

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = (14 sensors x $3,115 + $30,000), all multiplied by 330 sites = $24,291,300
- AC = $10,000 x 330 sites = $33,000,000
- PWV = $24,291,300 + 8.111 x $33,000,000 = $51,057,600
- ER = (0.40 tpd VOC) x (365 day/yr) x (10 years) = 1,460 tons VOC
- CE = $51,057,600 / 1,496 tons VOC reduced = $34,971/ton VOC reduced

Based on these assumptions, the cost-effectiveness for the use of stationary gas sensors is calculated to be $34,971/ton VOC reduced.

Staff considered both stationary gas sensors and the use of OGI cameras and calculated the incremental cost-effectiveness for both options. This analysis is included in the section "Incremental Cost-Effectiveness".

Open Path Sensors

Open path sensors are an alternative to stationary gas sensors and work in a different way by having a beam projected from a transmitter to a reflector. Staff did not find an oil and gas site using this type of technology; however, staff is aware that it is being used at oil refineries. The staff report from South Coast AQMD Rule 1178 included cost-effective data which was used for this staff report.

The following information was used to calculate the cost-effectiveness of purchasing and installing fenceline monitoring equipment:

- Number of oil and gas sites to be at approximately 330
- Cost of each sensor = $190,000
- Installation cost per sensor = $190,000
- Number of sensors at a site = 4
- Estimated life span of 20 years
- Annual maintenance = $5,000
- Emission reduction based on analysis conducted previously = 0.40 tpd VOC

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = (4 sensors x $380,000), all multiplied by 330 sites = $501,600,000
- AC = $5,000 x 330 sites = $1,650,000

- PWV = \$501,600,000 + 13.59 x \$1,650,000 = \$503,250,000
- ER = (0.40 tpd VOC) x (365 day/yr) x (20 years) = 2,920 tons VOC
- CE = \$503,250,000 / 2,920 tons VOC reduced = \$172,346/ton VOC reduced

Based on these assumptions, the cost-effectiveness for the use of open path sensors is calculated to be \$172,346/ton VOC reduced.

It should be noted that this type of enhanced leak detection technology exceeds the cost-effective VOC threshold.

*Engines Powered by Produced Gas*

Staff is proposing that engines that are powered by produced gas and are used to drive an oil producing meet a NOx standard of 11 ppmv @ 15% $O_2$ on a dry basis. Staff researched technologies that could be used to meet this standard and also the option to replace these engines with microturbines which is discussed in the next section. Staff obtained cost information for the technology upgrades from vendors that supply and service engines to oil and gas facilities. Staff also used cost information for exhaust emission controls that was collected for the November 2019 amendment to Rule 1110.2.

The following information was used to calculate the cost-effectiveness of upgrading engines powered by produced gas used to drive an oil producing well:

- Cost of 3-way catalyst = \$5,000
- Cost of air/fuel ratio controller = \$1,000
- Cost of installation of parts = \$5,000
- Estimated life span of 3 years for parts operating 24 hrs/day
- Annual maintenance = \$1,000
- Emission reduction based on analysis conducted previously = 0.0018 tpd NOx

- PWF = 2.78 for a 3-year life expectancy at 4% interest rate
- TIC = \$11,000
- AC = \$1,000
- PWV = \$11,000 + 2.78 x \$1,000 = \$13,775
- ER = (0.0018 tpd NOx) x (365 day/yr) x (3 years) = 1.971 tons NOx
- CE = \$13,775 / 1.971 tons NOx reduced = \$7,000/ton NOx reduced

Based on these assumptions, the cost-effectiveness for upgrading engines powered by produced gas used to drive an oil producing well is calculated to be \$7,000/ton NOx reduced.

*Microturbines Powered by Produced Gas*

As an alternative to requiring emissions controls on engines, staff is proposing that microturbines replace engines that use produced gas. The NOx emission standard for microturbines is 9 ppmv @ 15% $O_2$ on a dry basis. It is assumed that one microturbine would replace three engines that are each being used to drive three wells. Staff obtained cost information on microturbines from a local vendor that offers them for sale with South Coast AQMD's jurisdiction.

The following information was used to calculate the cost-effectiveness of purchasing a microturbine rated at 65 kilowatts (kW):

- Cost of microturbine = $150,000
- Microturbine installation cost = $300,000
- Cost of electric motor = $5,000 (x 3 for 3 electric motors) needed to drive wells
- Installation of electric motors = $5,000 (x3 for 3 electric motors) needed to drive wells
- Estimated life span of 10 years
- Annual maintenance = $10,000
- Emission reduction based on analysis conducted previously = 0.005 tpd NOx

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = $480,000
- AC = $10,000
- PWV = $480,000 + 8.111 x $10,000 = $561,110
- ER = (0.005 tpd NOx) x (365 day/yr) x (10 years) = 18.25 tons NOx
- CE = $561,110 / 18.25 tons NOx reduced = $30,700/ton NOx reduced

Based on these assumptions, the cost-effectiveness for installing a microturbine powered by produced gas used to drive an oil producing well is calculated to be $30,700/ton NOx reduced.

*Use of Tier 4 Final Workover Rigs*

Staff is proposing that engines on workover rigs be at least rated as Tier 4 Final. Staff obtained cost data from several operators that have either upgraded or replaced their workover rigs to be equipped with Tier 4 Final engines.

The following information was used to calculate the cost-effectiveness of purchasing a Tier 4 Final engine equipped workover rig:

- Cost of Tier 4 Final engine equipped workover rig = $1,000,000
- Estimated life span of 20 years
- Estimated number of Tier 4 Final engine equipped workover rigs needed to meet demand throughout South Coast AQMD's jurisdiction = 40

- Annual maintenance = $20,000
- Emission reduction based on analysis conducted previously = 0.51 tpd NOx

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = 40 rigs x $1,000,000 = $40,000,000
- AC = 40 rigs x  $20,000 = $80,000
- PWV = $40,000,000 + 13.59 x $800,000 = $50,872,000
- ER = (0.51 tpd NOx) x (365 day/yr) x (20 years) = 3,723 tons NOx
- CE = $50,872,000 / 3,723 tons NOx reduced = $13,700/ton NOx reduced

Based on these assumptions, the cost-effectiveness for replacing older model workover rigs with engines that are at least rated as Tier 4 Final is calculated to be $13,700/ton NOx reduced.

*Electrification of Workover Rigs*

Staff researched the feasibility of oil and gas production facilities using electrified workover rigs instead of workover rigs equipped with diesel engines. During the rule making process staff received cost information from the only two operators that currently have an electrified workover rig on their respective sites. No other facility was found to have an existing electrified rig. Staff found that a substation would need to be installed at *each* site in order to meet the electrical demands that an electrified workover rig would require.

The following information was used to calculate the cost-effectiveness of requiring an electrified workover rig:

- Number of oil and gas sites to be at approximately 330
- Cost of electrified workover rig = $10,000,000
- Cost of substation per site = $5,000,000
- Estimated life span of 20 years
- Estimated number of electrified workover rigs needed to meet demand throughout South Coast AQMD's jurisdiction = 40
- Annual Maintenance for the rigs = $20,000
- Annual Maintenance for the substations = $10,000
- Emission reduction based on analysis conducted previously = 0.54 tpd NOx

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = 40 rigs x $10,000,000 + 330 substations x $5,000,000 = $2,050,000,000
- AC = 40 rigs x  $20,000 + 330 substations x $10,000 = $4,100,000
- PWV = $2,050,000,000 + 13.59 x $4,100,000 = $2,054,100,000
- ER = (0.54 tpd NOx) x (365 day/yr) x (20 years) = 3,942 tons NOx

- CE = $2,054,100,000/ 3,942 tons NOx reduced = $521,080/ton NOx reduced

Based on these assumptions, the cost-effectiveness for replacing older model workover rigs with an electrified rig (and the installation of the requisite infrastructure) is calculated to be $521,080/ton NOx reduced.

It should be noted that the electrification of workover rigs exceeds the cost-effective NOx threshold.

*Elimination of Odorants*

The elimination of odorants is not expected to produce any significant reductions in VOC emissions. Moreover, the elimination of odorants does not result in any new cost incurred by operators, but rather it is a cost that is no longer spent. Therefore, no cost-effective analysis was conducted for this proposal.

*Improved Signage*

By producing and installing new signs at oil and gas production sites, some additional emission reductions may be generated, but these are expected to be one-time occurrences and are not expected to be significant. Staff acknowledges that there will be one-time costs associated with this proposal but does not consider these costs to be significant. Therefore, no cost-effective analysis was conducted for this proposal.

**INCREMENTAL COST-EFFECTIVENESS**

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments, relative to ozone, CO, SOx, NOx, and their precursors.

*Options for Enhanced Monitoring*

Staff conducted an incremental cost-effectiveness for OGI camera usage and stationary gas sensor monitoring as they both use enhanced technology for the detection of fugitive VOC emissions. Staff used the following formula to calculate incremental cost-effectiveness where option 1 is OGI monitoring and option 2 is stationary gas monitoring:

$$\text{Incremental Cost-Effectiveness} = \frac{\text{Cost of Option 2} - \text{Cost of Option 1}}{\text{Benefit of Option 2} - \text{Benefit of Option 1}}$$

$$\text{Incremental Cost-Effectiveness} = \frac{\$51{,}057{,}600 - \$13{,}688{,}000}{1{,}460 \text{ tons} - 990 \text{ tons}}$$

The incremental cost-effectiveness of using stationary gas sensors compared to OGI technology is calculated to be $79,510/ton VOC reduced.

Staff found that it was not cost-effective to use stationary gas sensors relative to OGI technology and therefore recommends the use of OGI technology as it is a more active and robust use of enhanced leak detection technology.

*Options for Tier 4 Final Engine versus Electrification*

Staff conducted an incremental cost-effectiveness for Tier 4 Final workover rigs versus electrified workover rigs where option 1 is the use of Tier 4 Final workover rigs and option 2 is the use of electrified workover rigs:

$$\text{Incremental Cost-Effectiveness} = \frac{\$2{,}050{,}000{,}000 - \$50{,}872{,}000}{3{,}942 \text{ tons} - 3{,}723 \text{ tons}}$$

The incremental cost-effectiveness of using electrified workover rigs compared to Tier 4 Final workover rigs is calculated to be $9,100,000/ton VOC reduced.

Staff found that it was not cost-effective to use electrified workover rigs relative to Tier 4 Final workover rigs.

## SOCIOECONOMIC IMPACT ASSESSMENT

Health and Safety Code Section 40440.8 requires a socioeconomic impact assessment for proposed and amended rules resulting in significant impacts to air quality or emission limitations. A Draft Socioeconomic Impact Assessment for PAR 1148.1 has been prepared and released for public review and comment on July 2, 2024. The Final Socioeconomic Impact Assessment is available in Attachment I of the August 2, 2024 Governing Board Package.

## CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) Guidelines Sections 15002(k) and 15061, the proposed project (PAR 1148.1) is exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3). A Notice of Exemption has been prepared pursuant to CEQA Guidelines Section 15062, and if the proposed project is approved, the Notice of Exemption will be filed with the county clerks of Los Angeles, Orange, Riverside, and San Bernardino counties, and with the State Clearinghouse of the Governor's Office of Planning and Research.

## DRAFT FINDINGS UNDER HEALTH AND SAFETY CODE SECTION 40727

*Requirements to Make Findings*

Health and Safety Code Section 40727 requires that the Board make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report. In order to determine compliance with Health and Safety Code Sections 40727 and 40727.2, a written analysis is required comparing the proposed amended rule with existing regulations.

*Necessity*

A need exists to amend PAR 1148.1 to implement best available retrofit control technology and emission reduction strategies recommended in the WCWLB and SLA CERPs as part of the AB 617 commitment.

*Authority*

The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations pursuant to Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, 40920.6, and 41508.

*Clarity*

PAR 1148.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by them.

*Consistency*

PAR 1148.1 is in harmony with and not in conflict with or contradictory to existing statutes, court decisions, or state or federal regulations.

*Non-Duplication*

PAR 1148.1 will not impose the same requirements as any existing state or federal regulations. The proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

*Reference*

In amending this rule, the following statutes which the South Coast AQMD hereby implements, interprets, or makes specific are referenced: Health and Safety Code Sections 39002, 40001, 40406, 40702, 40440(a), and 40725 through 40728.5.

## COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, the South Coast AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to oil and gas production activities. Because PAR 1148.1 does impose new inspection and reporting requirements, a comparative analysis was conducted.

Table 4-1: Comparative Analysis

| Topic | South Coast AQMD Rule 1148.1 Oil and Gas Notification Rule | San Joaquin Valley Air Pollution Control District | CalGEM | State of Colorado, Air Quality Control Commission | U.S. EPA |
|---|---|---|---|---|---|
| Newly Added Inspection Requirements | • Inspections with OGI camera<br>• Use of Tier 4 Final diesel engines on workover rigs<br>• Establish NOx limits for combustion equipment | • OGI usage requires quantification within 2 days of leak detection<br>• No relevant requirements for Tier 4 Final engines or NOx limits observed | • OGI usage allowed for inspections<br>• No relevant requirements for Tier 4 Final engines or NOx limits observed | • OGI allowed as alternative instrument monitoring and on drones<br>• Tier 4 engines required in impacted communities<br>• No relevant NOx limits observed | • OGI usage allowed with specific requirements for operator and equipment<br>• No relevant requirements for Tier 4 Final engines or NOx limits observed |
| Other amendments | • Notification when leak >25,000 ppmv detected<br>• Banning use of odorants | • Notification required to request extension for repair of leaking component<br>• No relevant requirements on odorant use observed | • Notification required for leaks > 50,000 ppmv or for leaks >10,000 ppmv persisting more than 5 days<br>• No relevant requirements on odorant use observed | • Notification within 5 days of discovery for unrepaired leaks<br>• No relevant requirements on odorant use observed | • No relevant requirements for notification or odorant use observed |
| Notes | | Reviewed Rule 4401 – Steam-Enhanced Crude Oil Production Wells | Reviewed Subarticle 13. Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities | Reviewed Regulation Number 7 of Colorado state Air Quality Control Commission regulations | Reviewed Appendix K "Determination of VOC and Greenhouse Gas Leaks Using Optical Gas Imaging" document |
| Links | https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1148-1 | https://ww2.valleyair.org/media/be1niqvx/rule-4401.pdf | https://ww2.arb.ca.gov/sites/default/files/2024-05/2024OilandGasRegulationunofficial.pdf | https://cdphe.colorado.gov/aqcc-regulations | https://www.epa.gov/system/files/documents/2021-11/40-cfr-part-60-appendix-k-proposal_0.pdf |

# APPENDIX A – RESPONSES TO COMMENT LETTERS

## Responses to Comments - Table of Contents

Comments from Public Workshop

Comment PW-1: Shannon Smith, Regulatory Compliance Supervisor from Signal Hill Petroleum had two questions: for OGI inspections, did staff factor in the cost of a toxic vapor analyzer (TVA) as part of the OGI camera cost-effectiveness? Second, did staff do mockup of the proposed signage requirement with four-inch lettering?

Response: Staff did not account for the cost of a TVA since using one during the proposed monthly OGI inspections is optional. Should an owner or operator opt to have a potential repair period consistent with South Coast AQMD Rule 1173, then the use of a TVA would be at their discretion. Second, staff initially proposed to include the signage requirements as promulgated in South Coast AQMD 1460 subdivision (g). However, since the Public Workshop was held, staff met with Signal Hill Petroleum staff and observed that the sign with four-inch lettering is excessively large. Staff is, therefore, proposing that lettering to be two-inches instead of four-inches which is still readable from a public street.

Comment PW-2: Emma Silber, Climate Justice Associate from Physicians for Social Responsibility expressed several concerns. First, by allowing the continued use of neutralizing agents, toxic contaminants would still be released into the air. Second, she was opposed to allowing Tier 4 Final engines to be used rather than requiring electrification. She stated that she had heard of a site that plugged in their workover rig into the electrical grid. Lastly, she expressed a concern over the efficiency of NOx incinerators.

Response: Staff is addressing the concern over the use of neutralizing agents by proposing that no toxic air contaminants listed in South Coast AQMD Rule 1401 would be allowed in any neutralizing agent and that no atomization of any neutralizing agents would be allowed. If a neutralizing agent were used by a site, these prohibitions are intended to prevent the use of air toxics and to keep the chemical from becoming airborne. Second, staff researched the potential electrification of workover rigs. Staff found that although options may exist to use electrically-powered drilling rigs, no commercially available option existed for workover rigs. Lastly, staff noted that NOx incinerators may be used for site-specific, soil remediation projects which would be regulated by South Coast AQMD Rule 1166.

Comment PW-3: Justin Martin, Manager from Pacific Coast Energy Co, asked if detection of visible vapors is in regards with the naked eye or with OGI equipment.

Response: Visible vapors is a new definition for this rule and is defined as VOC vapors detected visually by an operator or with an OGI device.

Comment PW-4: Richard Parks, President from Redeemer Community Partnership, made several comments. First, he commented that Warren E&P had electrified their workover operations and asked why we did not include this equipment in staff's technology assessment and analysis. Second, Mr. Parks expressed concern that allowing the use of neutralizing agents may not solve the issue of toxic air contaminants causing birth defects and that an odorant called "Chemco Odor Control Jasmine" had an endocrine disruptor. Lastly, Mr. Parks then requested information with whom the South Coast AQMD had spoken with regarding the reinjection of methane because reinjection was what he considered a zero-emission solution to produced gas.

Response: Staff had conducted a site visit to Warren E&P in Wilmington, prior to the Public Workshop, and found that an electrically-powered workover/drilling rig that was on site had been removed several years ago. While on-site, staff witnessed a diesel-powered workover rig conducting general well maintenance. Based on staff's direct observations, it was noted that Warren E&P does not operate an electrified workover nor electrified drilling rig. Second, staff is addressing concern over the use of neutralizing agents by proposing that no toxic air contaminants listed in South Coast AQMD Rule 1401 would be allowed in any neutralizing agent and that no atomization of any neutralizing agents would be allowed. If a neutralizing agent were used by a site, these prohibitions are intended to prevent the use of air toxics and to keep the chemical from becoming airborne. Also, staff reviewed the Safety Data Sheet for "Chemco Odor Control Jasmine" and found that it does contain a prohibited chemical that is listed in Rule 1401. Therefore, under the proposed prohibition, it would no longer be allowed to be used. Lastly, staff has met with staff from the city of Los Angeles Planning Department and found that the City of Los Angeles discourages the practice of gas reinjection within urban areas due to concerns of back pressure buildup underneath residents' homes and also due to the major gas leak that took place at Aliso Canyon a few years ago. In addition, since the Public Workshop took place staff met with CalGEM personnel and found that CalGEM has jurisdiction over the reinjection and storage of gas underground.

Comment PW-5: Mark Abramowitz, President from Community Environmental Services, asked why South Coast AQMD has not done a BARCT analysis for fuel cell technology and if South Coast AQMD had looked at the quality of the produced gas that is generated at oil and gas sites.

Response: Staff contacted several vendors of fuel cell technology and determined based on the information provided that the technology is not readily available for use on workover rigs. Staff acknowledges that this technology could become a viable option in the future. Second, operators that sell the produced gas to local gas companies must clean it up prior to selling it. Operators need to remove, at minimum, excess water prior to being used in microturbines.

Comment PW-6: Tianna (last name not provided), Environmental Justice Program Manager, raised two concerns. First, she questioned why electrified workover rigs were not required to be used. Second, she expressed concern with odorants and neutralizing agents. Tania asked if costs have been used in a cumulative way to include costs to taxpayers and residents due to particulate emissions for diesel-fueled workover rigs and concerns over endocrine disruptors in neutralizing agents. Concerns over cumulative harm were also raised.

Response: Staff conducted a cost-effectiveness analysis of proposed options and used the guidance for VOC and NOx cost-effectiveness found in the 2022 South Coast Air Quality Management Plan. In determining what is considered cost-effective for NOx, health effects were included. Staff conducted a cost-effective and emission reduction analyses for both Tier-4 Final engine upgrades and for electrification and found that while it was cost-effective to upgrade to Tier-4 Final engines, it was not cost-effective to use electrically-powered engines. Lastly, staff is addressing concern over the use of neutralizing agents by proposing that no toxic air contaminants listed in South Coast AQMD Rule 1401 would be allowed in any neutralizing agent and that no atomization of any neutralizing agents would be allowed.

<u>Comment PW-7:</u> Mark Abramowitz expressed concern over the allowance of 0.1% by weight of banned toxic air contaminants and that that amount would not be allowed in drinking water.

Response: Drinking water has much stricter standards because it is directly ingested. The allowance of 0.1% by weight is included for trace contaminants that are not purposely included in the odor neutralizer.

<u>Comment PW-8:</u> Erica Blyther, Petroleum Administrator for the City of Los Angeles Office of Petroleum and Natural Gas Administration and Safety, stated that she was pleased with South Coast AQMD requiring monthly OGI inspections and inquired on what constitutes a certified inspector for OGI device use.

Response: Thank you for your comment. There are now several vendors of OGI cameras and the intent of requiring the user of an OGI camera to complete a manufacturer's certification or training program is to ensure that the user of such equipment is well versed in the use of such equipment. Staff also recognizes that the training course(s) may differ depending on the manufacturer.

<u>Comment PW-9:</u> Emma Silber asked if detected leaks during inspections would be made public.

Response: Since the Public Workshop was held, staff is proposing to require the operator to submit a notification whenever a leak is quantified and found to be greater than 25,000 ppmv of VOC. For those that have signed up to receive Rule 1148.2 notifications, they will now also receive notifications for reported leaks greater than 25,000 ppmv of VOC.

Comment Letter 1: Signal Hill Petroleum, Received 2/9/2024

SIGNAL HILL PETROLEUM

American Energy.
American Jobs.

February 7, 2024

Jose Enriquez, Air Quality Specialist
South Coast Air Quality Management District
Planning, Rule Development and Area Sources
21865 Copley Dr.
Diamond Bar, CA 91765

RE: Signal Hill Petroleum, Inc.'s comments regarding preliminary draft language of Proposed Amended Rule 1148.1.

Dear Mr. Enriquez and 1148.1 Rulemaking Team,

Signal Hill Petroleum (SHP) is a privately-owned California -based energy company that specializes in the exploration and production of crude oil and natural gas in urban areas. With a set of core values rooted in a transparent business philosophy, honest approach, and concern for the environment, our company strives to be an excellent neighbor and community partner. The SHP Regulatory Team has been following the development of Proposed Rule 1148.1. Per your request, we have drafted comments on the recently released draft rule language. Please see our comments below:

> (c)(34) WORKOVER RIG is a mobile piece of equipment used to perform one or more operations on an oil producing well or water injection well

This definition, while also present in Rule 1148.2, is too broad. A "mobile piece of equipment" could include trucks and other smaller tools. We suggest that you use ARB's definition of workover rig (2449(c)(62)): "a mobile self-propelled rig used to perform one or more remedial operations, such as deepening, plugging back, pulling and resetting liners, on a producing oil or gas well to try to restore or increase the well's production." 1-1

> (d)(17) Effective [Three years from date of rule amendment], the operator of an oil and gas production facility shall use workover rigs that are equipped with an engine that meets the emissions standards of a Tier 4 Final engine. 1-2

2633 Cherry Ave. Signal Hill, CA 90755 | T: 562. 595.6440 | F: 562. 426.4587 | W: shpi.net

While SHP already has all Tier 4 Final Workover Rigs in our fleet, we would like to point out that this is already being regulated by the California Air Resources Board In-Use Off-Road Diesel-Fueled Fleets Regulation, in which every fleet in California phases out older engines for new Tier 4 Final or electric engines. 1-2 Cont.

> (d)(13) …signage shall: (A) Be installed within 50 feet of the main entrance to the facility and in a location that is visible to the public; (B) Measure at least 30 inches wide by 30 inches tall; (C) Display lettering at least 4 inches tall with text color contrasting with the sign background; (D) Located at least 4 feet above grade from the bottom of the sign;

As currently proposed these signs would be nearly impossible to achieve, impractical to maintain, and an eye sore to the community. SHP has made a quick example of what is being proposed and the pictures are an attachment to this letter. The first requirement, (d)(13)(A) which requires the sign to be installed within 50 feet of the entrance, is too specific and impractical. An operator could post the signs across the street or inside their facility and still be fully compliant with the rule. The second requirement (d)(13)(B), which requires the sign to be at least 30" by 30", should be reconsidered. The 4" lettering does not fit on a 30" by 30" poster. This is also not a typical poster size. 24" by 36" would be more standard although still much larger than any other sign SHP currently has. 1-3 Our company signs with our Facility name and phone number measure 30" by 12" and our neighbors have no problem reading them. The third requirement (c)(13)(C), which requires 4" lettering, is not practical. As you can see from the attached photos, 4" lettering in both English and Spanish would be a billboard rather than an entrance sign. We also created an example of 2" lettering in English only and it is also huge and not practical to post at our facilities. The fourth requirement (d)(13)(D) requires the sign to be 4 feet off the ground minimum. If the signs are posted on the entrance fence (and not 50 feet away) then the sign can be no higher than 2 feet since most standard fences are 6 feet tall. Anything protruding above that could interfere with barbed wires and the security of the enclosure.

This one-size-fits-all approach does not work for urban upstream oil and gas operations. It may make sense for a large facility distanced from the public view, such as in Rule 1460, but doesn't make sense for production sites next door to businesses and homes. We recommend editing the original language to allow for flexibility among operators while still achieving your goal of having the signs visible and readable by the public. We specifically recommend removing requirements (d)(13)(A) through (d)(13)(D) and either not specifying a size or recommending a standard size for the signage without text size requirements.

> (e)(6)(B)(ii) When visible vapors are detected using an OGI Device, use an appropriate analyzer in compliance with paragraph (j)(1) to quantify the visible vapors in ppmv concentration within 48 hours of when the vapors are detected; 1-4

SHP owns three OGI cameras and currently uses them to detect any potential leaks in our facilities. While monthly OGI inspections and recordkeeping will be challenging, we believe it is feasible to accomplish this. What makes the OGI camera so useful is that our operators can visit a facility, FLIR the facility, and if they find a leak, they can repair it immediately and move on. If our crew needed to quantify the leak before repairing it, that would require time to (1) acquire a TVA, (2) find and measure the leak with the TVA, (3) report the leak to the district and (4) look up the repair thresholds in accordance with Rule 1173, all before fixing the actual leak. This is time spent allowing the leaks to continue in order to quantify and document the leaks. Also, SHP has looked into and rented a TVA (Total Vapor Analyzer) in compliance with EPA specifications and found that the maintenance and calibration requirements were extremely onerous. Calibration gases would have to be stored on-site and the TVAs calibrated every day. In addition, the TVAs require maintenance more often than a FLIR camera. SHP would have to purchase multiple TVA units to always have two or three units on hand in case of a leak in order to comply with this requirement.

1-4 Cont.

SHP recommends that you adopt the rule language in Rule 1178 (f)(4)(A) "If determined that Visible Vapors are emitted from components required to be maintained in a Vapor Tight Condition or in a condition with no Visible Gaps, the owner or operator shall make necessary repairs or adjustments… within 3 days". This would ensure that leaks are fixed promptly and that all components could be inspected in a timely manner, once a month in compliance with the new proposed rule requirements.

Please let us know if you have any questions or wish to discuss our comments further. You may contact Shannon Smith at (562) 326-5246 or ssmith@shpi.net.

Sincerely,

Shannon Smith
Regulatory Compliance Supervisor

Attachments:
Photo #1 – Proposed signage with 4" lettering in English only
Photo #2 – Proposed signage with 2" lettering in English only

Comment 1-1: The definition for workover rig was incorporated from South Coast AQMD Rule 1148.2 for consistency among rules that use this definition. The definition is somewhat vague so that it may allow for future technologies that could become commercially available such as electrically-powered or fuel-cell powered rigs. In addition, adding that it be self-propelled would not cover all rigs since some exist that use a secondary engine to do well work and the primary engine to drive the rig itself.

Comment 1-2: Staff conducted a cost-effective and emission reduction analyses for both Tier-4 Final engine upgrades and for electrification and found that while it was cost-effective to upgrade to Tier-4 Final engines, it was not cost-effective to require the use of electrically-powered engines. In addition, staff researched a company that already manufactures electric drilling rigs and found that the footprint and power requirements such a rig would require to be too large for the majority of oil and gas sites that are found within South Coast AQMD's jurisdiction as many of these sites are less than a half-acre in size. Additionally, a substation would be necessary as well as power lines and electric grid that could handle the power requirements of 373 kilowatts which is equivalent to a 500-HP diesel engine. Finally, drilling activities represent a small fraction of activities at oil and gas facilities.

CARB already has a requirement for In-Use Off-Road Diesel-Fueled Fleets regulation, however, depending on the size of the operator's fleet, it could take longer than the effective date of this rule before an operator would be required to upgrade their fleet by CARB's compliance date. Therefore, this requirement aims to bridge the gap that may exist between this rule and CARB's rule.

Comment 1-3: Staff reviewed the signage requirements and agreed that the minimum size of the lettering was too large and has since reduced the minimum size from 4 inches to 2 inches. This change will not affect the intent of this updated requirement which aims to have signage be visible from a public street.

Comment 1-4: Staff agrees that it is preferable to repair leaks discovered with an OGI camera sooner rather than later and the proposed amended rule language has been updated such that any leaks found exclusively with an OGI camera shall be repaired within twenty-four hours of discovery. If using an OGI camera in conjunction with a calibrated handheld device that can quantify leaks, the operator can follow Rule 1173 subdivision (g) ~~Repair Period Table~~ which could give the operator additional time to repair those leak(s).

Comment Letter 2: STAND LA, Received 2/15/2024

February 10, 2024

Mr. Wayne Nastri, Executive Officer
South Coast Air Quality Management District
21865 Copley Dr, Diamond Bar, CA 91765

Re: Proposed Amended Rule 1148.1 - Oil and Gas

Dear Mr. Nastri:

Rule 1148.1 - Oil and Gas presents opportunities to substantially reduce nitrogen oxides (NOx) emissions and protect the health of residents, especially those of frontline communities. Southern California still needs to reduce smog-forming NOx by more than 100 tons per day in order to achieve the 1997 standard for ozone.[1]

The Stand Together Against Neighborhood Drilling (STAND-LA) coalition of frontline environmental justice organizations have actively participated in the Air District's AB617 and the 1148.1 rule-making processes to protect communities disproportionately impacted by air pollution.

We remain concerned that the proposed amended Rule 1148.1 does not yet incorporate our recommendations to reduce NOx and protect public health. We seek action in three areas:

1. Zero-emission workover operations
2. Zero toxics in odor counteractants (including neutralizing agents)
3. Zero combustion of produced methane

**Zero-emission Workover Operations**

We request that the Air District evaluate the cost effectiveness of using electric utility power or other zero-emission auxiliary sources to power the current fleet of mobile, diesel workover rigs. The adaptive electrification of existing mobile equipment may prove far more health and climate 2-1

[1] Los Angeles smog woes worsen as U.S. EPA threatens to reject local pollution plan, Los Angeles Times, (February 4, 2024)

protective than utilizing Tier-4 engines alone, and clearly more cost effective than acquiring $10 million electric rigs at each of 40 oil drill sites.

In 1999, the Breitburn oil company boasted that the use of an electrically-powered derrick at the Pico/Doheny Drill Site would eliminate most diesel emissions.[2] Diesel engine emissions are responsible for about 70% of California's estimated known cancer risk attributable to toxic air contaminants.[3] It is vitally important that the Air District evaluate lower-cost electrification alternatives to protect public health, rather than simply ruling out the most expensive approach. 2-1 Cont.

**Zero toxics in odor counteractants**

AB617 communities raised concerns about odorants because they contain powerful, toxic chemicals that cause birth defects, damage fertility, and cause multi-generational reproductive harm. Banning odorants while defining a new class of "neutralizing agents" that are permitted to have toxic air contaminants in their formulation up to 0.1%-by weight, does not address our community's concerns. It appears to be a change in words, but not practice.

The National Institute of Environmental Health Sciences notes,

> "Even low doses of endocrine-disrupting chemicals may be unsafe. The body's normal endocrine functioning involves very small changes in hormone levels, yet we know even these small changes can cause significant developmental and biological effects. This observation leads scientists to think that endocrine-disrupting chemical exposures, even at low amounts, can alter the body's sensitive systems and lead to health problems."[4]

The appropriate threshold for any toxics in odor counteractants is zero. We do not want more toxics dispersed in our communities. 2-2

Chemco Odor Control Jasmine is a common odor counteractant used at oil drill sites. It contains 4-no-nyl-pheenol, branched, ethoxylated, a endocrine disrupting chemical (EDC) that causes birth defects. Will the Air District categorize it as an odorant or a "neutralizing agent"? The public needs clarity from the Air District about which odor counteractants will be banned, which will be allowed, and which toxics that the Air District will allow in odor counteractant formulations, if any.

Our position remains that Chemco Odor Control Jasmine and other odor counteractants should not be permitted for use.

The staff report states that "Neutralizing agents work to 'knock out' or eliminate the odors." (page 3-5). That implies some sort of chemical manipulation, for example chemical decomposition. However, the manipulation that happens is often to human olfactory receptors--

[2] Neighbors Take On Pico Oil Drilling Site, Jewish Journal (November 25, 1999)
[3] Propper et al. 2015. Environmental Science & Technology **49**(19):11329–11339.
[4] National Institute of Environmental Health Sciences website. Downloaded 2/6/2024 from https://www.niehs.nih.gov/health/topics/agents/endocrine#:~:text=Even%20low%20doses%20of%20endocrine,significant%20developmental%20and%20biological%20effects.

knocking them out.[5] The presence of toxic gasses such as hydrogen sulfide or benzene are not eliminated, only the ability to detect them. Odor counteractants and "neutralizing agents" solve the wrong problem precisely. 2-2 Cont.

Toxic trespass into the bodies of our children and families must stop. The appropriate threshold for any toxics--including endocrine disruptors--in odor counteractants, odorants, and neutralizing agents is zero.

**Zero combustion of produced methane**
Reinjection of produced methane is a common zero emission oil field practice. The EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review affirms reinjection of produced gas into the oil field as an effective strategy for regulating greenhouse gasses (GHGs) and volatile organic compounds (VOCs) emissions for the Crude Oil and Natural gas source category pursuant to the Clean Air Act. We ask the District to evaluate reinjection of produced methane as a viable and cost effective zero emission practice that will enhance air quality and public health, especially for residents living near oil field operations. 2-3

STAND-LA would welcome the opportunity to discuss these concerns with the 1148.1 rule-making team. Thank you for your consideration.

Sincerely,
Richard Parks, President, Redeemer Community Partnership

Maro Kakoussian, Director of Climate and Health Programs, Physicians for Social Responsibility Los Angeles & STAND-LA Coalition Coordinator

Tianna Shaw Wakeman, Environmental Justice Program Manager, Black Women for Wellness

Reverend Louis Chase, Holman United Methodist Church

Rabeya Sen, Policy Director, Esperanza Community Housing

cc:
Mayor Pro Tem Larry McCallon, Chair
Supervisor Holly J. Mitchell, Vice Chair
Councilmember Michael A. Cacciotti

[5] Yosuke Fukutani, Masashi Abe, Haruka Saito, Ryo Eguchi, Toshiaki Tazawa, Claire A. de March, Masafumi Yohda, Hiroaki Matsunami, Antagonistic interactions between odorants alter human odor perception, Current Biology, Volume 33, Issue 11, 2023, Pages 2235-2245.e4, https://doi.org/10.1016/j.cub.2023.04.072. Accessed 2/8/2024 from https://www.sciencedirect.com/science/article/pii/S0960982223005547/

Senator (Ret.) Vanessa Delgado
Board Member Veronica Padilla-Campos
Mayor José Luis Solache
Trish Johnson, CARB Office of Community Air Protection
Liliana Nunez, CARB Air Pollution Specialist
Michael Krause, SCAQMD Assistant Deputy Executive Officer
Michael Morris, SCAQMD Planning and Rules Manager
Rodolfo Chacon, SCAQMD Program Supervisor
Jose Enriquez, SCAQMD Air Quality Specialist

Comment 2-1: Staff conducted cost-effective and emission reduction analysis for both Tier-4 Final engine upgrades and for electrification and found that while it was cost-effective to upgrade to Tier-4 Final engines it was not cost-effective to upgrade to electrification options. The cost to upgrade to Tier 4 Final engines was found to be $13,700/ton of NOx reduced whereas the cost to electrify was found to be $521,080/ton of NOx reduced.

In addition, staff researched a company that already manufactures electric drilling rigs and found that their footprint and power requirements would be too large for the majority of oil and gas sites that are found within South Coast AQMD's jurisdiction as many of these sites are less than a half-acre in size. Also, a substation would be necessary, as well as power lines and electric grid that could handle the power requirements of 373 kilowatts which is equivalent to a 500-HP diesel engine.

Staff acknowledges that future developments in electrification and other technologies such as fuel cells may mature enough to be usable in a variety of oil and gas sites including smaller urban and remote sites. This rule may be reopened in the future to add the use of cleaner technologies. In addition, CARB's Advanced Clean Fleet Regulation, as of 2024, will require electrification of workover rigs starting in year 2036 which would cover the entire state.

Comment 2-2: Staff has proposed the ban of the use of odorants. Additionally, staff has also restricted the use of neutralizing agents by prohibiting the use of any neutralizing agents that contain more than 0.1% by weight of toxic air contaminants pursuant to South Coast AQMD Rule 1401 – New Source Review of Toxic Air Contaminants. The Safety Data Sheet for the chemical that was referenced, "Chemco Odor Control Jasmine" includes a chemical listed in South Coast AQMD's Rule 1401 and would therefore no longer be allowed to be used once the effective date of this amended rule passes. To further reduce the chance of fugitive odors, staff is also prohibiting the atomizing of neutralizing agents whenever they are used.

Comment 2-3: Staff reviewed how produced gas is handled and recognizes that there are four options to use it: selling to a gas company, using it in onsite equipment such as microturbines or engines, reinjecting back into the ground, or flaring it.

Staff researched the reinjection of the produced gas into the ground and found that the City of Los Angeles discourages the practice of reinjection within urban areas due to concerns of back pressure build up underneath residents' homes and with the major gas leak that took place at Aliso Canyon a few years ago. In addition, CalGEM has jurisdiction over the reinjection and storage of gas underground and carries its own permit requirements.

The use of produced gas in microturbines is more favorable to the City of Los Angeles. Another advantage of using produced gas in microturbines is that it would provide some relief to the area's power grid and is a cleaner way to use it compared to flaring. Staff has added NOx requirements to ensure these emissions remain low. Staff has also added NOx emissions if the facility uses the produced gas in engines that drive oil and gas wells.

Comment Letter 3: Center for Biological Diversity, Received 2/15/2024

CENTER *for* BIOLOGICAL DIVERSITY *Because life is good.*

February 15, 2024

Jose Enriquez
Planning, Rule Development, and Implementation
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765

Re: Comments on Proposed Amended Rule 1148.1 – Oil and Gas

Dear Mr. Enriquez:

These comments are submitted on behalf of the Center for Biological Diversity regarding the Proposed Amended Rule 1148.1. Though the proposed amendments take positive steps in curbing harmful emissions from oil and gas production facilities, we remain concerned that the proposed amendments do not go far enough, namely in three areas:

1. Establishing zero-emission workover rig operations
2. Eliminating concerns regarding the use of odorants
3. Alerting the public in the event of leak detection

The Stand Together Against Neighborhood Drilling (STAND-LA) coalition is submitting comments with many of the same concerns. We agree with STAND-LA's comments and see our comments as supporting those while contributing added perspective.

**1. Establishing Zero-Emission Workover Rig Operations**

There is no disputing that electrifying workover rigs would drastically reduce harmful emissions from oil and gas well workover operations, but SCAQMD staff ultimately did not recommend electric rigs because of concerns about cost-effectiveness. It is indeed the case that electrified workover rigs exceed the cost-effectiveness threshold based on SCAQMD staff's analysis. However, it is noted that a "cost-effectiveness that is greater than the threshold of $325,000 per ton of NOx reduced would also require additional analysis and a hearing before the Governing Board on costs."[1] Similar guidance is given for exceeding the cost-effectiveness threshold for VOC reductions. Thus, the initial assessment Staff provided of cost-effectiveness does not preclude further consideration of electrifying workover rigs. Given that maximizing public health benefit should not be relegated to a mere cost equation, it seems appropriate to conduct additional analysis (perhaps including a search for lower-cost electrification alternatives) along with a hearing by the Governing Board to further weigh the merits of electrifying workover operations. 3-1

[1] Staff Report, p. 4-6.

Arizona . California . Colorado . Florida . N. Carolina . Nevada . New Mexico . New York . Oregon . Washington, D.C. . La Paz, Mexico
BiologicalDiversity.org

## 2. Eliminating Concerns Regarding the Use of Odorants

SCAQMD staff propose eliminating the use of odorants which have been traditionally used to mask odors coming from oil and gas production sites. This is the right action since odorants themselves can be a nuisance to communities and present health harms. However, as a substitute, staff propose what essentially constitutes another category of odorant—neutralizing agent. Purportedly, neutralizing agents "work to 'knock out' or eliminate the odors, as opposed to masking the odors," while containing none of the toxics "listed in Rule 1401 in quantities greater than 0.1 percent by weight."[2] This new category of odorant gives several reasons for concern. 3-2

First, the Rule 1401 list is not exhaustive, and could not possibly capture the full list of potential toxics that could be found in neutralizing agents. This is more so the case given that the neutralizing agents to be used are not identified. If neutralizing agents are to be taken as an innocuous alternative to odorants, the neutralizing agents allowed should be limited and clearly identified so that it is certain that none have the potential of yielding toxic emissions.

Second, the proposal limits Rule 1401 toxics to quantities less than 0.1 percent by weight, but this ignores the fact that some toxics have no true safe limit, including some on the Rule 1401 list.[3] For instance, bis(2-ethylhexyl)phthalate is on the Rule 1401 list, but it is part of the chemical group *phthalates*, which are well known endocrine disruptors.[4] Even low doses of endocrine-disrupting chemicals may be unsafe. Phthalates are very common, found in various fragrances, packaging, and cosmetics. Given their ubiquity, it is possible that such a chemical could end up in an unspecified neutralizing agent. Therefore, the provision on limiting neutralizing agents based on the Rule 1401 list is not rigorous enough to ensure non-harmful emissions.

Third, we are skeptical that a neutralizing agent would truly "knock out" or eliminate odors. To truly eliminate an odor would mean either eliminating the source of the odor or capturing vapors before they reach individuals. If this is truly the function of the proposed neutralizing agents, then great, but otherwise neutralizing agents constitute nothing more than a masking agent, same as classic odorants. And masking agents, rather than lessening the public nuisance posed by noxious fumes, merely cover up the presence of those fumes, thereby hiding the threat posed. Concerns regarding this could at least be partially addressed by providing a list of neutralizing agents to be used and the mechanisms by which they eliminate odors.

## 3. Alerting the Public in the Event of Leak Detection

SCAQMD staff have proposed the use of optical gas imaging (OGI) cameras to identify leaks at oil and gas production sites. This comes with two requirements: (1) "If a visible vapor is observed while inspecting with an OGI camera, the operator will be required to quantify in parts per million by volume (ppmv), any VOC emissions within 48 hours of when visible vapors are 3-3

[2] Staff Report, p. 3-6.
[3] SCAQMD, Regulation XIV – Toxics and Other Non-Criteria Pollutants, Rule 1041 – New Source Review of Toxic Air Contaminants (Accessed February 14, 2024), http://www.aqmd.gov/docs/default-source/rule-book/reg-xiv/rule-1401.pdf.
[4] National Institute of Environmental Health Sciences, Endocrine Disruptors (Accessed February 14, 2024), https://www.niehs.nih.gov/health/topics/agents/endocrine.

detected"; and (2) "should a visible vapor be quantified where the emission level triggers a repair, replacement, or removal of a component…then a notification to South Coast AQMD will also be required to be made within 24 hours of such quantification."[5] These requirements should come with additional notifications to the public.

In the event of a leak, the public should be made aware of the leak quantity and composition and be provided with an assessment of whether there is a community threat posed. Further, should a repair be necessary, the public should be made aware of when the issue will be resolved, whether emissions will be ongoing during the repair, and whether there will be any nuisances resulting from the repair, such as noise or further emissions. Similar to the disclosures required under Rule 1148.2 of chemical usage and operations at oil and gas sites, Rule 1148.1 should require disclosures on leaks and measures to repair them.

3-3 Cont.

***********************************

We appreciate your engagement thus far on the proposed Rule 1148.1 amendments. We implore you to consider these remaining concerns to make Rule 1148.1 the most robust and the most protective of community health.

Respectfully submitted,

John Fleming, Ph.D.
Senior Scientist
Center for Biological Diversity

[5] Staff Report, p. 3-6.

Comment 3-1: Please see response under comment 2-1.

Comment 3-2: Please see response under comment 2-2.

Comment 3-3: Staff has added an amendment to this rule to require the operator to submit a notification whenever a leak is quantified and found to be greater than 25,000 ppmv VOC. Notifications of reported leaks will be included in Rule 1148.2 notifications, for those who have signed up to receive them.

Comment Letter 4: FracTracker Alliance, Received 4/11/2024

FRACTRACKER ALLIANCE

# Oil and Gas Fugitive Emissions from Combustors in the South Coast Air District

Requirements for California Air Resources Board (CARB)-approved emissions reduction technology and infrastructure cannot be a replacement for stringent monitoring and inspections. The existing work of grassroots organizations, including Redeemer Community Partnership, STAND-LA, PSR-LA and research groups like FracTracker Alliance, has monitored the compliance of drill sites in the Los Angeles Basin, and has shown the failures of engineering protections when sites are not regularly and thoroughly inspected.[1] This work includes the filmed documentation of many California Air Resources Board-approved burners observed to be operating poorly, inefficiently combusting methane and other volatile organic compounds (VOCs) that were still observable at concentrated levels in the exhaust streams. This is not an issue limited to southern California, as other geographies such as Colorado are also addressing the issue, as required by recent rulings of the U.S. Environmental Protection Agency.[2] 4-1

The implementation of the California Air Resources Board (CARB) Oil and Gas Methane Regulation in 2018 was the first time that regulators even considered that oil and gas operators should not be directly venting toxic and carcinogenic VOCs from wash and crude tanks. The elimination of venting was the most important regulatory intervention for reducing community exposures to hydrocarbon emissions. Operators were no longer able to completely disregard the uncontrolled release of pollutants and subsequent degradation of local airsheds, due to the establishment of actionable limits to methane concentrations in fugitive emissions. While the rule applies to all fugitive emissions and leaks, tank venting was by far the most widespread source of fugitive emissions, present at nearly every wellsite without existing evaporative emissions control systems (EVAP). 4-2

The various California air districts have taken a range of different approaches to the implementation of the CARB methane regulation. While the Yolo-Solano Air Quality Management District, with natural gas fields in the northern San Joaquin Valley, has largely ignored the rule altogether, districts such as the San Joaquin Valley Air Pollution Control District, Ventura County, and Santa Barbara County have all stepped up inspections and have all issued violations for tank emissions. The South Coast Air Quality Management District has taken a leadership position, utilizing existing local rule 1148.1 to require operators to install EVAP 4-3

[1]https://www.fractracker.org/2022/08/fractracker-finds-widespread-hydrocarbon-emissions-from-active-idle-oil-and-gas-wells-and-infrastructure-in-california/
[2]https://biologicaldiversity.org/w/news/press-releases/epa-rejects-air-pollution-permits-for-oil-gas-wells-in-colorado-2024-02-01/

systems and require the use of CARB-certified combustors to ensure the destruction of methane and other VOCs into carbon dioxide prior to being released into the atmosphere.[3] 4-3 Cont.

Since the implementation of the methane rule, FracTracker has conducted dozens of thermographic inspections of oil and gas facilities in the LA Basin using Forward Looking Infrared (FLIR) optical gas imaging (OGI) cameras. Inspections were completed in collaboration with grassroots organizations by the FracTracker Alliance Western Program Director, a certified thermographer. The installation of EVAP systems and combustors drastically reduced the documented volumes of fugitive emissions, as compared to on-site OGI inspections conducted prior to the installation of combustors. 4-4

While the concentrations and volumes of VOCs emitted from tank venting were vastly reduced, the combustion units themselves were observed to be a new source of methane and VOC releases. The exhaust streams of multiple units had observable concentrations of hydrocarbons.
Example 1: Warren E&P Field
Example 2: Murphy Drill Site
Example 3: Deist Tank Farm
Example 4: Rosecrans Field

Industry and regulators alike often stress the perspective that oil and gas extraction operations can occur in populated areas without degrading the environmental health of communities, if proper engineering protections are in place and best practices followed. Such organizations point to a variety of engineering protections such as EVAP systems and low-NOx burners that, when functioning properly, can prevent leaks from key components of wellhead infrastructure and efficiently combust waste gas. They say that with these engineering standards, hydrocarbons can be extracted from even urban residential environments without harming communities. 4-5

This perspective is patently false. Engineering protections alone are not effective, because oil and gas wellheads are incredibly leak-prone. The many opportunities for large leaks and the combination of many small undetectable leaks provide ample exposure pathways to degrade local and regional air quality with a cocktail of harmful volatile organic compounds. Wellhead infrastructure includes a variety of pipelines, connected by gasketed flanges and valves, all operating under high pressure. Leaks form regularly, and while they are often easily fixed by replacing equipment or just retorquing bolts, they cannot be addressed if they are not identified.

In lieu of eliminating oil and gas extraction operations in communities or requiring all associated gas be collected and refined, FracTracker Alliance urges the South Coast Air District to establish a robust inspection program that increases the oversight of exhaust streams from combustors. In addition to on-site inspections by SCAQMD staff using OGI cameras and methane sniffers, concentrations of methane and VOCs in the inflow and exhaust streams of combustion units should be measured to ensure the units are performing at the maximum possible efficiency. Additionally, these units should be sampled regularly, at least monthly, to ensure the operational efficiency remains within regulatory parameters. 4-6

[3] https://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1148-1.pdf

Comment 4-1: Staff recognizes the challenges involved in creating stringent requirements versus verifying compliance with such requirements and appreciates the involvement of grassroot organizations to verify compliance.

Comment 4-2: South Coast AQMD Rule 463 – Organic Liquid Storage applies to most storage tanks and includes requirements for leak detection and repair, domes, seals, and other control equipment. For tanks that are exempt from Rule 463, Rule 1148.1 covers produced gas emissions from smaller tanks located in oil and gas sites.

Comment 4-3: Thank you for your comment.

Comment 4-4: Staff recognizes the effectiveness of using OGI technology in assisting in locating leaks and has therefore proposed implementing the use of such technology in Rule 1148.1 and other rules.

Comment 4-5: Staff is implementing NOx limits and source tests to the combustion equipment that is used on oil and gas sites, such as microturbines and engines that drive wells. Also, staff is implementing the use of OGI technology and notification submission of quantified leaks greater than 25,000 ppmv VOC.

Comment 4-6: Staff is adding a new requirement to PAR 1148.1 that would require oil and gas operators to perform monthly inspections with an optical gas imaging camera. Additionally, for any leaks that are quantified to be greater than 25,000 ppmv VOC the operator will be required to submit a notification.

**ATTACHMENT H**

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 • www.aqmd.gov

**SUBJECT:** **NOTICE OF EXEMPTION FROM THE CALIFORNIA ENVIRONMENTAL QUALITY ACT**

**PROJECT TITLE:** **PROPOSED AMENDED RULE 1148.1 – OIL AND GAS PRODUCTION WELLS**

Pursuant to the California Environmental Quality Act (CEQA) Guidelines, the South Coast Air Quality Management District (South Coast AQMD), as Lead Agency, has prepared a Notice of Exemption pursuant to CEQA Guidelines Section 15062 – Notice of Exemption for the project identified above.

If the proposed project is approved, the Notice of Exemption will be filed for posting with the county clerks of Los Angeles, Orange, Riverside, and San Bernardino Counties. The Notice of Exemption will also be electronically filed with the State Clearinghouse of the Governor's Office of Planning and Research for posting on their CEQAnet Web Portal which may be accessed via the following weblink: https://ceqanet.opr.ca.gov/search/recent. In addition, the Notice of Exemption will be electronically posted on the South Coast AQMD's webpage which can be accessed via the following weblink: http://www.aqmd.gov/nav/about/public-notices/ceqa-notices/notices-of-exemption/noe---year-2024.

# NOTICE OF EXEMPTION FROM THE CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

| | | | |
|---|---|---|---|
| **To:** | County Clerks for the Counties of Los Angeles, Orange, Riverside, and San Bernardino; and Governor's Office of Planning and Research – State Clearinghouse | **From:** | South Coast Air Quality Management District<br>21865 Copley Drive<br>Diamond Bar, CA 91765 |

**Project Title:** Proposed Amended Rule 1148.1 – Oil and Gas Production Wells

**Project Location:** The proposed project is located within the South Coast Air Quality Management District's (South Coast AQMD) jurisdiction, which includes the four-county South Coast Air Basin (all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino counties), and the Riverside County portion of the Salton Sea Air Basin and the non-Palo Verde, Riverside County portion of the Mojave Desert Air Basin.

**Description of Nature, Purpose, and Beneficiaries of Project:** Rule 1148.1 was developed to reduce emissions of volatile organic compounds (VOC), toxic air contaminants, and total organic compounds from the operation of wellheads, well cellars, and the handling of produced gas at oil and gas production facilities. The objective of Proposed Amended Rule (PAR) 1148.1 is to further reduce and control these emissions. PAR 1148.1 will : 1) add new definitions to clarify rule requirements; 2) require the use of enhanced leak detection technology; 3) require equipment that uses produced gas to meet specific oxides of nitrogen (NOx) limits and to verify compliance via source tests; 4) require workover rigs to use minimum Tier 4 Final diesel engines; 5) ban the use of odorants that are used to mask odors emanating from oil production sites; 6) update signage requirements to include a minimum size and certain instructions; and 7) include additional minor changes to rule language for consistency and clarity. Initial projections indicate that PAR 1148.1 is expected to require some physical modifications involving minimal to no construction activities associated with: 1) upgrading the engines of approximately 30 workover rigs from Tier 2 to Tier 4 Final; 2) retrofitting approximately 17 engines with 3-way catalysts; 3) installing approximately four microturbines; and 4) conducting optical gas imaging inspections. Implementation of PAR 1148.1 is expected to result in emission reductions of 98.55 tons per year of VOC by 2025, 18.47 tons per year of NOx by 2026, and 186.15 tons per year of NOx by 2027 which will benefit public health and ambient air quality.

| **Public Agency Approving Project:** | **Agency Carrying Out Project:** |
|---|---|
| South Coast Air Quality Management District | South Coast Air Quality Management District |

**Exempt Status:** CEQA Guidelines Section 15061(b)(3) – Common Sense Exemption

**Reasons why project is exempt:** South Coast AQMD, as Lead Agency, has reviewed the proposed project (PAR 1148.1) pursuant to: 1) CEQA Guidelines Section 15002(k) – General Concepts, the three-step process for deciding which document to prepare for a project subject to CEQA; and 2) CEQA Guidelines Section 15061 – Review for Exemption, procedures for determining if a project is exempt from CEQA. The analysis of the anticipated physical changes that may occur as a result of implementing PAR 1148.1 indicates that since minimal to no construction activities are expected, it can be seen with certainty that implementing the proposed project would not cause a significant adverse effect on the environment. Therefore, the proposed project is exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3) – Common Sense Exemption.

**Date When Project Will Be Considered for Approval (subject to change):**
South Coast AQMD Governing Board Public Hearing: August 2, 2024

| **CEQA Contact Person:** | **Phone Number:** | **Email:** | **Fax:** |
|---|---|---|---|
| Sina Taghvaee, Ph.D. | (909) 396-2192 | staghvaee@aqmd.gov | (909) 396-3982 |
| **PAR 1148.1 Contact Person:** | **Phone Number:** | **Email:** | **Fax:** |
| Jose Enriquez | (909) 396-2640 | jenriquez1@aqmd.gov | (909) 396-3982 |

**Date Received for Filing:** ______________ **Signature:** *(Signed and Dated Upon Board Approval)*

Kevin Ni
Program Supervisor, CEQA
Planning, Rule Development, and Implementation

**SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT**

# Final Socioeconomic Impact Assessment For: Proposed Amended Rule 1148.1 – Oil and Gas Production Wells

## August 2024


**Deputy Executive Officer**
Planning, Rule Development, and Implementation
Sarah L. Rees, Ph.D.

**Assistant Deputy Executive Officer**
Planning, Rule Development, and Implementation
Michael Krause

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| **Authors:** | Chris Yu – Assistant Air Quality Specialist<br>Daniel Penoyer – Air Quality Specialist |
| **Technical Assistance:** | Jose Enriquez – Air Quality Specialist<br>Rodolfo Chacon – Program Supervisor |
| **Reviewed By:** | Xian-Liang (Tony) Tian, Ph.D. – Program Supervisor<br>Shah Dabirian, Ph.D. – Consultant<br>Erika Chavez – Senior Deputy District Counsel |

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**EXECUTIVE SUMMARY**

On March 17, 1989, the South Coast Air Quality Management District (South Coast AQMD) Governing Board adopted a resolution which requires an analysis of the economic impacts associated with adopting and amending rules and regulations. In addition, Health and Safety Code Section 40440.8 requires a socioeconomic impact assessment for any proposed rule, rule amendment, or rule repeal which "will significantly affect air quality or emissions limitations." Lastly, Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for a proposed rule or amendment which imposes Best Available Retrofit Control Technology (BARCT) or "all feasible measures" requirements relating to emissions of ozone, carbon monoxide (CO), sulfur oxides (SOx), nitrogen oxides (NOx), volatile organic compounds (VOC), and their precursors.

Proposed Amended Rule 1148.1 (PAR 1148.1) has been developed to reduce the emissions of volatile organic compounds (VOC), toxic air contaminants (TAC), and total organic compounds (TOC) from wellheads and well cellars located at oil and gas production facilities. A socioeconomic impact assessment has been conducted accordingly, and the following presents a summary of the analysis and findings of the socioeconomic impact assessment conducted for PAR 1148.1.

**Key Elements of PAR 1148.1**

PAR 1148.1 would require oil and gas production facilities to take measures to reduce VOC, TAC, and TOC emissions from the operation of wellheads and well cellars and improve the handling of produced gas. These emission reductions would be achieved by requiring enhanced leak detection, establishing emission limits for internal combustion engines (ICEs) and microturbines powered by produced gas, and requiring cleaner engines on workover rigs.

**Affected Facilities and Industries**

PAR 1148.1 affects approximately 323 facilities, with 240 located in Los Angeles County, 81 located in Orange County, and two located in San Bernardino County. All the affected facilities are classified under the Oil and Gas Extraction industry according to the North American Industry Classification System (NAICS) code 211.

A small business analysis was also conducted for the facilities affected by PAR 1148.1. The following table presents the number of affected facilities that qualify as a small business under each definition used in the analysis.

| Definition | Number of Facilities |
|---|---|
| South Coast AQMD Rule 102 | 59 |
| South Coast AQMD's Small Business Assistance Office | 241 |
| U.S. Small Business Administration | 255 |

**Assumptions for the Analysis**

The key requirements of PAR 1148.1 that have cost impacts include: 1) Optical Gas Imaging (OGI) cameras and inspection for leak detection; 2) NOx emission limits for engines and microturbines that are powered by produced gas; 3) source testing of engine and microturbine emissions; and 4) more stringent engine standards for workover rigs.

Specifically, PAR 1148.1 would likely cause the purchase and maintenance of OGI cameras, as well as training and labor costs to use these cameras for leak detection. Compliance with new emission limits for engines powered by produced gas would likely be achieved by the installation of 3-way catalysts and associated air pollution control equipment which requires annual maintenance and would be verified periodically by source tests. Finally, workover rigs would be retrofitted with Tier 4 Final engines which also require incremental annual maintenance expenditures.

This analysis projects the costs of implementing the control measures from 2025 to 2046. This analysis assumes that affected facilities purchase OGI cameras, 3-way catalysts, and Tier 4 Final engines in 2025, 2026, and 2027, respectively, which are the most cost-effective control strategies to comply with the requirements of PAR 1148.1.

**Compliance Costs**

The total present value of the compliance cost for PAR 1148.1 is estimated at $92.0 million and $66.4 million for a 1% and 4% discount rate, respectively. The average annual compliance cost of PAR 1148.1 is estimated to range from $4.1 million to $4.7 million for a 1% to 4% real interest rate, respectively. When using a 4% real interest rate, this analysis indicates roughly 53% of the annual average compliance cost would be incurred by Tier 4 Final engine expenses, followed by OGI expenses (43%), 3-way catalyst expenses (3%), and source testing expenses (1%).

The following table presents a summary of the average annual cost of PAR 1148.1 by cost category.

| Cost Categories | Annual Average Cost of PAR 1148.1 (2025-2046) | |
|---|---|---|
| | 1% Real Interest Rate | 4% Real Interest Rate |
| **Capital Costs** | | |
| OGI Camera | $1,254,441 | $1,422,588 |
| 3-Way Catalyst & Air/Fuel Controller | $48,203 | $49,611 |
| 3-Way Catalyst Installation | $40,169 | $41,342 |
| Workover Rig with Tier 4 Final Engine | $1,496,363 | $1,929,591 |
| **Recurring Costs** | | |
| OGI Inspection Labor | $480,000 | $480,000 |
| OGI Camera Maintenance | $100,000 | $100,000 |
| OGI Camera Training | $50,000 | $50,000 |
| 3-Way Catalyst & Air/Fuel Controller Maintenance | $23,864 | $23,864 |
| Tier 4 Final Engine Maintenance | $545,455 | $545,455 |
| Source Testing | $64,773 | $64,773 |
| **Total** | **$4,103,267** | **$4,707,223** |

**Job Impacts**

Direct costs and corresponding spending of PAR 1148.1 are used as inputs to the Regional Economic Models, Inc (REMI PI+) model to assess job impacts and secondary/induced impacts for all the industries in the four-county economy on an annual basis from 2025-2046.

When the compliance cost is annualized using a 4% real interest rate, the REMI analysis forecasted 28 net jobs foregone annually in the four-county region on average over the forecast period, relative to the baseline forecast. Note that the jobs foregone mainly implies less job growth compared to the baseline scenario, not necessarily indicating the loss of current jobs. The jobs foregone are mainly attributable to the necessary equipment that facilities would have to install and purchase due to the implementation of PAR 1148.1. The largest job impacts occur in year 2033 when the REMI model forecasts 44 jobs foregone relative to the baseline scenario. However, the model also predicts 35 and 16 jobs gained in 2025 and 2027, respectively, due to the benefits from capital expenditures of affected facilities.

**Competitiveness and Price Impacts**

The overall impacts of PAR 1148.1 on production cost and delivered prices in the region are expected to be minimal. The REMI model indicates PAR 1148.1 will lead to a maximum increase of 0.44% and 0.02% on production cost and delivered price, respectively, in year 2027.

## INTRODUCTION

In 2004, the South Coast AQMD Governing Board adopted Rule 1148.1, which sought to reduce VOC emissions from wellheads and well cellars at oil and gas production facilities through increased inspection and maintenance, and controls for produced gas emissions. Rule 1148.1 applies to facilities engaged in activities like drilling, well completion, well rework, and well injection.

Rule 1148.1 was amended in 2015 after South Coast AQMD took enforcement action at an urban oil and gas production facility due to odor nuisances.~~, in addition to increased concerns in local communities about potential environmental impacts from oil extraction techniques such as hydraulic fracturing.~~ The objectives of these amendments were to: 1) minimize impacts on residents and sensitive receptors; 2) improve work practices; and 3) establish odor mitigation procedures.

PAR 1148.1 was developed to further reduce emissions of volatile organic compound (VOC), toxic air contaminants (TAC), and total organic compounds (TOC) from the operation of wellheads, well cellars, and handling of produced gas at oil and gas production facilities.

## LEGISLATIVE MANDATES

The legal mandates directly related to the socioeconomic impact assessment of PAR 1148.1 include South Coast AQMD Governing Board resolutions and various sections of the Health and Safety Code.

### South Coast AQMD Governing Board Resolution

On March 17, 1989, the South Coast AQMD Governing Board adopted a resolution that requires an analysis of the economic impacts associated with adopting and amending rules and regulations that considers all of the following elements:

- Affected industries;
- Range of probable costs;
- Cost-effectiveness of control alternatives; and
- Public health benefits.

### Health and Safety Code Requirements

The state legislature adopted legislation which reinforces and expands the South Coast AQMD Governing Board resolution requiring socioeconomic impact assessments for rule development projects. Health and Safety Code Section 40440.8, which went into effect on January 1, 1991, requires a socioeconomic impact assessment for any proposed rule, rule amendment, or rule repeal which "will significantly affect air quality or emissions limitations."

To satisfy the requirements in Health and Safety Code Section 40440.8, the scope of the socioeconomic impact assessment should include all of the following information:

- Type of affected industries;
- Impact on employment and the regional economy;
- Range of probable costs, including those to industry;
- Availability and cost-effectiveness of alternatives to the rule;

- Emission reduction potential; and
- Necessity of adopting, amending, or repealing the rule in order to attain state and federal ambient air quality standards.

Health and Safety Code Section 40728.5, which went into effect on January 1, 1992, requires the South Coast AQMD Governing Board to: 1) actively consider the socioeconomic impacts of regulations; 2) make a good faith effort to minimize adverse socioeconomic impacts; and 3) include small business impacts. To satisfy the requirements in Health and Safety Code Section 40728.5, the socioeconomic impact assessment should include the following information:

- Type of industries or business affected, including small businesses; and
- Range of probable costs, including costs to industry or business, including small business.

Finally, Health and Safety Code Section 40920.6, which went into effect on January 1, 1996, requires an incremental cost-effectiveness analysis for a proposed rule or amendment which imposes Best Available Retrofit Control Technology (BARCT) or "all feasible measures" requirements relating to emissions of ozone, carbon monoxide (CO), sulfur oxides (SOx), nitrogen oxides (NOx), VOC, and their precursors. A BARCT assessment has been conducted and can be found in Chapter 2 of the Final ~~Draft~~ Staff Report.[1]

**AFFECTED FACILITIES**

PAR 1148.1 would affect an estimated 323 onshore oil and/or gas well facilities. Out of these 323 affected facilities, 240 (74%) are located in Los Angeles County, 81 (25%) are located in Orange County, and two (1%) are located in San Bernardino County. All the affected facilities are classified under the Oil and Gas Extraction industry according to the North American Industry Classification System (NAICS) code 211 and either belong to the industries of Crude Petroleum Extraction (NAICS 211120) or Natural Gas Extraction (NAICS 211130). Staff estimated that the 323 affected facilities are owned by approximately 100 parent companies.

**SMALL BUSINESS**

The South Coast AQMD defines a "small business" in Rule 102 for purposes of fees as one which employs 10 or fewer persons and which earns less than $500,000 in gross annual receipts. The South Coast AQMD also defines "small business" for the purpose of qualifying for access to services from the South Coast AQMD's Small Business Assistance Office (SBAO) as a business with an annual receipt of $5 million or less, or with 100 or fewer employees. In addition to the South Coast AQMD's definition of a small business, the federal Small Business Administration (SBA) and the federal 1990 Clean Air Act Amendments (1990 CAAA) each have their own definition of a small business.

The 1990 CAAA classifies a business as a "small business stationary source" if it: 1) employs 100 or fewer employees; 2) does not emit more than 10 tons per year of either VOC or NOx; and 3) is a small business as defined by the SBA. Based on firm revenue and employee count, the SBA

[1] South Coast AQMD, Preliminary Draft Staff Report for Proposed Amended Rule 1148.1 – Oil and Gas Production Wells, https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1148_2/par-1148-1-preliminary-draft-staff-report-final.pdf, accessed July 16, 2024. The Final Staff Report is located in Attachment G of the August 2, 2024 Governing Board package for PAR 1148.1, which upon posting, will be available 72 hours prior to the Governing Board meeting at https://www.aqmd.gov/home/news-events/meeting-agendas-minutes.

definition of a small business varies by six-digit NAICS codes.[2] For example, facilities in the Crude Petroleum Extraction (NAICS 211120) and Natural Gas Extraction (NAICS 211130) sectors will be considered a small business if they employ 1,250 or fewer people.

South Coast AQMD mostly relies on Dun & Bradstreet data to conduct a small business analysis on privately owned companies. In cases where the Dun & Bradstreet data are unavailable or unreliable, other external data sources such as Manta, Hoover, and LinkedIn data will be used. The determination of data reliability is based on data quality confidence codes in the Dun & Bradstreet data as well as staff's discretion. Revenue and employee data for publicly owned companies is gathered from Securities and Exchange Commission (SEC) filings. Since subsidiaries under the same parent company are interest-dependent, the revenue and employee data of a facility's parent company will be used for the determination of its small business status. Employment and revenue data from 2023 Dun & Bradstreet as well as other external sources are available for only 291 facilities. Note that although the employment and revenue data for some facilities are unknown or missing, the current data used for this small business analysis represent the most thorough and accurate information obtainable as of the date of the final report. However, staff was unable to determine small business classification for the affected facilities using the 1990 CAAA definition because most of these facilities are not required to submit annual emission reports under South Coast AQMD Rule 222 – Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II and thus, their emissions data are not available.[3] Table 1 presents the number of small businesses based on each definition.

**Table 1**
**Number of Affected Small Business Facilities Based on Various Definitions**

| Definition | Number of Facilities |
|---|---|
| South Coast AQMD Rule 102 | 59 |
| South Coast AQMD's Small Business Assistance Office | 241 |
| U.S. Small Business Administration | 255 |

[2] U.S. Small Business Administration, 2023 Small Business Size Standards, https://www.sba.gov/document/support-table-size-standards, accessed July 16, 2024.
[3] South Coast AQMD, Rule 222 – Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II, https://www.aqmd.gov/docs/default-source/rule-book/reg-ii/Rule-222.pdf, accessed July 16, 2024.

## COMPLIANCE COST

The elements of PAR 1148.1 which have potential cost impacts include: 1) enhanced leak detection requirements involving OGI inspections, 2) NOx emission limits for equipment using produced gas and compliance verification through source testing, and 3) Tier 4 Final engine standards for workover rigs.

This analysis assumes equipment purchases and services for control measures required by PAR 1148.1 are paid directly to equipment suppliers and service providers, and that OGI inspections are administered by the facilities using their own staff. Overall, this socioeconomic impact assessment takes a conservative approach to cost estimation, and some of the cost estimates may be slightly higher than the estimates discussed in the Final ~~Draft~~ Staff Report in order to account for uncertainty in certain costs. Capital and other one-time costs include OGI cameras, 3-way catalysts and air/fuel controllers for ICEs powered by produced gas, and Tier 4 Final Engines for workover rigs. Recurring costs include maintenance for OGI cameras, 3-way catalysts, and Tier 4 Final engines, OGI camera inspection labor, OGI camera training, and source testing for ICE engines and microturbines. Manufacturer-provided specifications for microturbines indicate that this equipment can achieve the NOx emission limit of 9 parts per million by volume (ppmv), and this analysis assumes that no additional emissions control technology will be required for these units.

While there are alternative air pollution control technologies discussed in the Final ~~Draft~~ Staff Report which affected facilities could use to comply with the requirements of PAR 1148.1, this analysis assumes that facilities will choose the lowest cost technologies and will purchase equipment in the year the compliance deadline goes into effect. The compliance cost for PAR 1148.1 is forecasted for a 22-year period from 2025 to 2046, reflecting the expected purchase of OGI cameras in 2025 and a 20-year useful life of Tier 4 Final engines, which are expected to be purchased in 2027. The expected purchase dates are based on the proposed compliance deadlines of PAR 1148.1. All estimates of the compliance cost are presented in 2023 dollars.

Many of the costs estimated in this analysis are dependent on site-specific factors and on business decisions made by facilities subject to PAR 1178.[4] Staff strove to represent costs as realistically as possible, given that many factors would ultimately dictate what price a business will pay to implement a control. The estimated cost for each item was either estimated based on quotes from equipment manufacturers or service providers, data provided by affected facilities, or internal South Coast AQMD data. The procedure and assumptions for each cost estimate are discussed in the next section and the costs are presented in 2023 dollars.

### Capital/One-Time Costs

#### OGI Cameras

PAR 1148.1 requires monthly Optical Gas Imaging (OGI) inspection to detect leaks from equipment more promptly than current inspection techniques and frequency allow. OGI cameras can detect vapors from leaking equipment by visualizing a variety of gas wavelengths. Staff

[4] South Coast AQMD Rule 1178 – Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities was amended in September 2023 to include OGI inspections, https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1178, Accessed July 16, 2024.

identified roughly 100 parent companies for the 323 affected facilities. Each parent company is assumed to purchase an OGI camera in 2025, the first year of rule compliance, and that OGI cameras will be used to perform leak inspections at all the affected facilities owned by the parent company. According to vendors and affected facilities, each camera will cost approximately $120,000 and have an anticipated 10-year useful life. Since costs are forecasted until 2046, each parent company is expected to purchase an OGI camera three times within the forecast horizon, with a total cost of $36 million.

**3-way Catalyst and Air/Fuel Controller**

For the affected facilities that utilize produced gas to power stationary ICEs onsite, PAR 1148.1 would require those engines to comply with a NOx emission standard of 11 ppmv, corrected to 15% oxygen (O2) on a dry basis, which is the same as what is required in Rule 1110.2 for stationary engines. Based on the BARCT analysis discussed in the Final ~~Draft~~ Staff Report, this analysis assumes that 3-way catalysts paired with air/fuel controllers will be installed on the affected equipment to meet this NOx emission standard. Staff obtained cost estimates both from equipment manufacturers and existing cost information on exhaust emission controls collected during the November 2019 amendment to Rule 1110.2. The cost of a 3-way catalyst, air/fuel ratio controller, and installation of these components is estimated to be $5,000, $1,000, and $5,000, respectively. Based on site visits to the affected facilities, an estimated 25 ICEs fueled by produced gas will each need to be retrofitted with a 3-way catalyst and an air/fuel ratio controller. The estimated useful life for this equipment is three years. The 3-way catalysts and air/fuel controllers are assumed to be installed in 2026, with a total of seven replacements over the forecast period, yielding an estimated total cost of $1.9 million.

**Tier 4 Final Workover Rigs**

PAR 1148.1 would require workover rigs be equipped with an engine that meets the emissions standards of a Tier 4 Final engine. Staff estimated that there are currently 40 workover rigs utilized at the affected facilities to conduct maintenance activities on oil producing wells or water injection wells. Staff was able to obtain costs from several operators that have already retrofitted their workover rigs with Tier 4 Final engines, which is approximately $1,000,000 per workover rig, with an expected useful life of 20 years. On site visits, staff observed that 10 workover rigs have already been retrofitted with Tier 4 Final engines, with 30 remaining workover rigs requiring a retrofit. This analysis assumes the 30 workover rigs will be retrofitted in 2027, with an estimated total cost of $30 million.

## Recurring Costs

**OGI Camera Training**

Training by OGI camera manufacturers is required to ensure proper operation of this equipment. Training is expected to occur every two years and cost approximately $1,000 per trainee. Staff assumed one existing employee at each of the 100 parent companies will receive OGI training, resulting in a total cost of $100,000 every two years. The first training is anticipated to occur in 2025, with 11 total training sessions over the forecast period, yielding a total cost of $1.1 million.

**Labor for OGI Inspection**

PAR 1148.1 requires monthly OGI inspections at each facility to detect potential leaks. This analysis assumes that the inspections will be conducted by employees of facilities' parent companies and that the monthly inspection will take one day on average to inspect all the facilities under the same parent company. With an assumed wage rate of $50 per hour, the total annual labor cost associated with the inspection is estimated at $4,800 for each parent company (1 person x 8 hrs/day x $50/hr x 12 inspections/yr). For all 100 parent companies, the total yearly cost will be $480,000. Since inspections will occur once a month over the 22-year forecast period, the total labor cost for OGI inspections is estimated to be $10.6 million.

#### OGI Camera Maintenance

Annual maintenance is necessary for OGI cameras to ensure that equipment is calibrated and working properly. Each camera has an expected annual maintenance cost of $1,000, yielding a total annual cost of $100,000 for the 100 cameras. Maintenance will begin in 2025, the first year when OGI cameras are purchased, and will occur annually throughout the forecast period, bringing the total cost of OGI camera maintenance to roughly $2.2 million.

#### 3-Way Catalyst and Air/Fuel Controller Maintenance

Annual maintenance and calibration are necessary for 3-way catalysts and air/fuel controllers to ensure the equipment is operating at maximum efficiency. Each 3-way catalyst has an annual maintenance cost of approximately $1,000 and all of the 25 ICEs fueled by produced gas will need to be retrofitted with a 3-way catalyst. As such, maintenance expenses are projected to begin in 2026 with an average annual maintenance cost of $25,000, resulting in a total estimated maintenance cost of $525,000 over the forecast period.

#### Tier 4 Final Workover Rig Maintenance

Starting in 2027, annual maintenance will be necessary for workover rigs equipped with Tier 4 Final engines to ensure that they continue to meet the more stringent emission standards in PAR 1148.1. Each workover rig has an estimated annual maintenance cost of $20,000, yielding a total annual maintenance cost of $600,000 for all 30 rigs and a total cost of $12 million over the forecast period.

#### Source Testing

Periodic source testing of ICEs and microturbines powered by produced gas will be required within two years after PAR 1148.1 is adopted and every five years thereafter. According to discussions with vendors and affected facilities, each source test is estimated to cost between $3,000 and $5,000. As a conservative approach, this analysis assumes a cost of $5,000 per source test. Source tests are required on an estimated universe of 32 existing microturbines and 25 ICEs, for a cost of $285,000 in the years when source testing is required, and a total cost of $1.4 million over the forecast period.

### Total Compliance Cost

The average annual cost of implementing PAR 1148.1 includes the estimated amortized capital and recurring compliance costs averaged over the period from 2025 to 2046. For the calculation of the present value of total compliance costs, all the annual compliance costs will be discounted to 2024, the anticipated first year PAR 1148.1 is adopted. [5]

The present value of estimated compliance cost is estimated at $92.0 million and $66.4 million for a 1% and 4% discount rate, respectively. The average annual compliance cost of PAR 1148.1 is estimated to range from $4.1 million to $4.7 million for a 1% to 4% real interest rate, respectively.[6] Table 2 presents the present value of estimated compliance costs and the average annual compliance cost of PAR 1148.1 by cost categories.

**Table 2**
**Total Present Value and Annual Average Estimated Costs of PAR 1148.1**

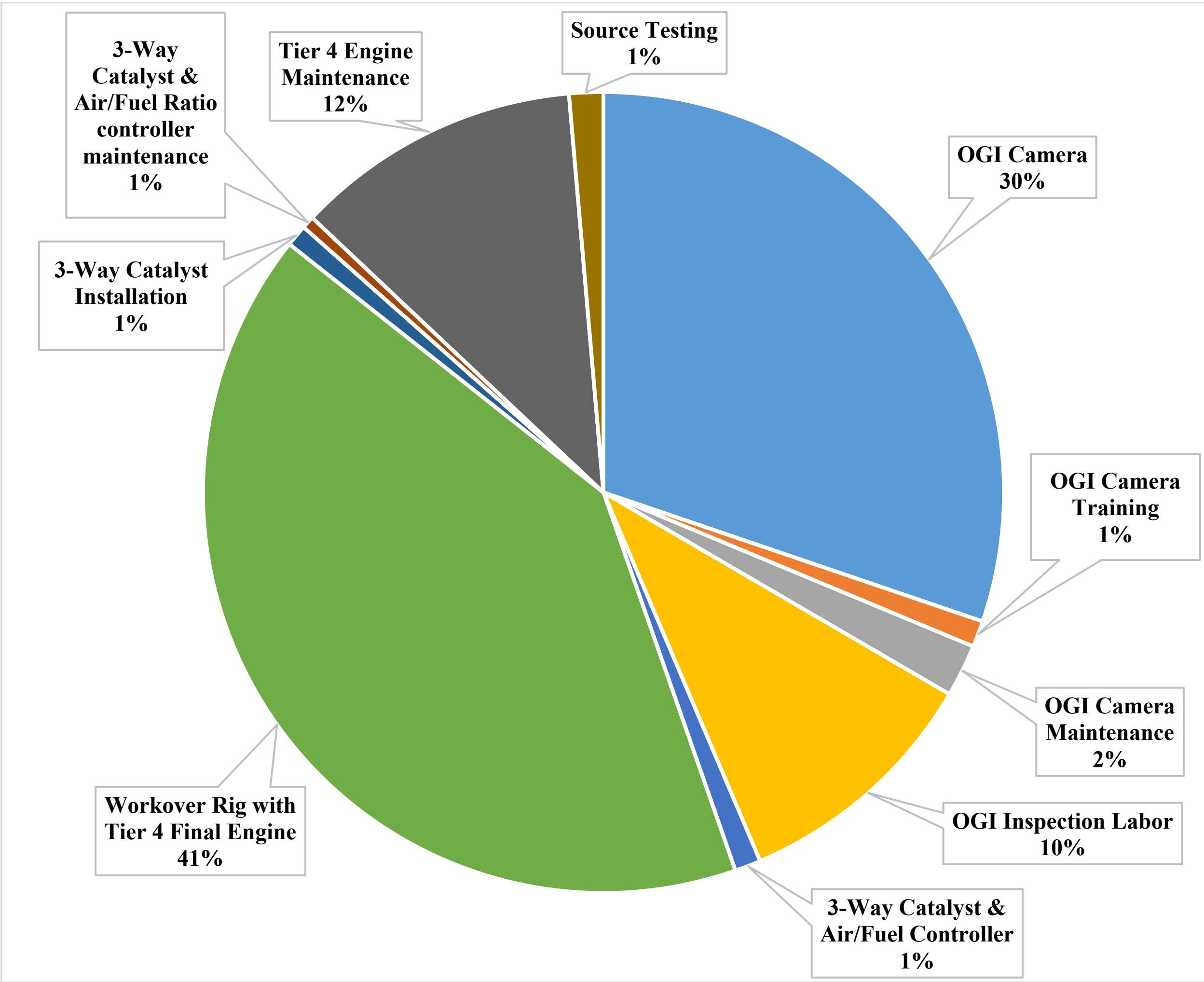
| Cost Categories | Present Value (2024) | | Annual Average (2025 – 2046) | |
|---|---|---|---|---|
| | 1% Discount Rate | 4% Discount Rate | 1% Real Interest Rate | 4% Real Interest Rate |
| **Capital Costs** | | | | |
| OGI Camera | $27,968,616 | $20,557,981 | $1,254,441 | $1,422,588 |
| 3-Way Catalyst & Air/Fuel Controller | $970,357 | $701,098 | $48,203 | $49,611 |
| 3-Way Catalyst Installation | $808,631 | $584,249 | $40,169 | $41,342 |
| Workover Rig with Tier 4 Final Engine | $37,547,885 | $26,669,891 | $1,496,363 | $1,929,591 |
| **Recurring Costs** | | | | |
| OGI Inspection Labor | $9,436,982 | $6,936,535 | $480,000 | $480,000 |
| OGI Camera Maintenance | $1,966,038 | $1,445,112 | $100,000 | $100,000 |
| OGI Camera Training | $987,910 | $736,724 | $50,000 | $50,000 |
| 3-Way Catalyst & Air/Fuel Controller Maintenance | $466,757 | $337,239 | $23,864 | $23,864 |
| Tier 4 Final Engine Maintenance | $10,613,991 | $7,539,012 | $545,455 | $545,455 |
| Source Testing | $1,264,748 | $924,654 | $64,773 | $64,773 |
| **Total** | **$92,034,913** | **$66,432,495** | **$4,103,267** | **$4,707,223** |

Figure 1 presents the estimated average annual compliance costs of PAR 1148.1 by cost category. Maintenance of workover rigs, OGI cameras and Tier 4 Final engines account for the largest portions of the average annual compliance cost at 41%, 30% and 12%, respectively. All the estimated compliance costs will be incurred by the industry of Oil and Gas Extraction (NAICS 211).

5 A discount rate in is used to find the present value of a stream of future payments, reflecting the idea that costs borne in the future are worth less than costs incurred in the present day.

6 Real interest rate is defined as the nominal interest rate adjusted for inflation, reflecting the true cost of borrowing.

**Figure 1**
**Total Annual Estimated Costs of the PAR 1148.1 by Expense Category**




## MACROECONOMIC IMPACTS ON THE REGIONAL ECONOMY

The Regional Economic Models, Inc (REMI) 2024 PI+ v3 model was used to assess the socioeconomic impacts of PAR 1148.1.[7] The model links the economic activities in the counties of Los Angeles, Orange, Riverside, and San Bernardino, and it is comprised of five interrelated blocks: 1) output and demand; 2) labor and capital; 3) population and labor force; 4) wages, prices, and costs; and 5) market shares.[8]

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7 Regional Economic Modeling Inc. (REMI). Policy Insight® for the South Coast Area (70-sector model). Version 3. 2023.

8 Within each county, producers are made up of 156 private non-farm industries and sectors, three government sectors, and a farm sector. Trade flows are captured between sectors as well as across the four counties and the rest of U.S. Market shares of industries are dependent upon their product prices, access to production inputs, and local infrastructure. The demographic/migration component has 160 ages/gender/race/ethnicity cohorts and captures population changes in births, deaths, and migration. (For details, please refer to REMI online documentation at http://www.remi.com/products/pi.).

It should be noted that the REMI model is not designed to assess impacts on individual operations. The model was used to assess the impacts of the proposed amended rule on various industries that make up the local economy. Cost impacts on individual operations were assessed outside of the REMI model and were aggregated to the 70-sector NAICS code level to be used as inputs into the REMI model.

**Impact of PAR 1148.1**

This assessment is performed relative to a baseline ("business as usual") forecast where PAR 1148.1 would not be implemented. The analysis assumed that the 323 affected facilities would finance the capital and installation costs of equipment at a 4% real interest rate, and that these one-time costs are amortized and incurred over the useful life of the equipment.

Direct costs of PAR 1148.1 are used as inputs to the REMI model which relies on this information to assess secondary and induced impacts for all the industries in the four-county economy on an annual basis over the 2025-2046 period. Direct effects of PAR 1148.1 include equipment, labor, training, and other costs discussed in the previous compliance cost section.

While the compliance expenditures that are expected to be incurred by the affected facilities would increase their cost of doing business, the purchase of the required equipment and services would increase the sales and subsequent spending of businesses in various sectors, some of which may be located in South Coast AQMD's jurisdiction. Table 3 lists the 70-sector NAICS codes modeled in REMI that would incur either as a direct cost or direct benefit from this anticipated compliance costs/spending.

**Table 3**
**Industries Incurring and Benefitting from Compliance Costs/Spending**

| Source of Compliance Cost | REMI Industries Incurring Compliance Costs (NAICS) | REMI Industries Benefitting from Compliance Spending (NAICS) |
|---|---|---|
| OGI Camera | Oil and Gas Extraction (211) | *Capital & Recurring:* Computer and Electronic Product Manufacturing (334) |
| OGI Camera Maintenance | | |
| OGI Camera Training | | |
| OGI Inspections | | *N/A** |
| 3-Way Catalyst & Air/Fuel Controller | | *Capital:* Machinery Manufacturing (333) |
| 3-Way Catalyst Installation | | |
| 3-Way Catalyst & Air/Fuel Controller Maintenance | | *Recurring:* Repair and Maintenance (811) |
| Tier 4 Final Engine Maintenance | | |
| Workover Rig with Tier 4 Final Engine | | *Capital:* Transportation Equipment Manufacturing (336) |
| Source Testing | | *Recurring:* Professional, Scientific, and Technical Services (541) |

*The wage income earned by employees conducting OGI inspections is modeled as an increase in compensation for employees in the Oil and Gas Extraction industry and thus does not directly benefit a single industry.

**Regional Job Impacts**

In the REMI model, costs were distributed to each county based on the share of affected facilities in that county. Table 4 presents the forecasted jobs foregone and gained in the four-county economy for selected industries and years. When the compliance cost is annualized using a 4% real interest rate, the REMI model projects that there will be 28 jobs foregone on average over the 2025-2046 period relative to the baseline forecast. However, the jobs foregone can be considered minimal as they only represent 0.002% of the average forecasted baseline number of jobs in the regional economy. The largest forecasted jobs foregone occur in 2032 with 42 jobs foregone relative to the baseline forecast. For specific industries, the sectors of Construction (NAICS 23), Professional, Scientific, and Technical Services (NAICS 54), Oil and Gas Extraction (NAICS 211), and State and Local Government are expected to lose seven, four, four and three jobs on average, respectively, relative to the baseline forecast. The anticipated jobs foregone can be attributed to the increased spending that affected facilities have to incur to comply with PAR

1148.1. However, the REMI analysis shows that the sectors of Repair and Maintenance (NAICS 811) and Computer and Electronic Product Manufacturing (NAICS 334) are expected to gain three and two jobs on average, respectively, relative to the baseline forecast. The anticipated job gains are the result of the purchase of capital equipment and maintenance expenditures. Note that in Table 4, the "All Industries" row includes the full set of 70 industrial sectors modeled in the REMI software, including the 10 selected industries.

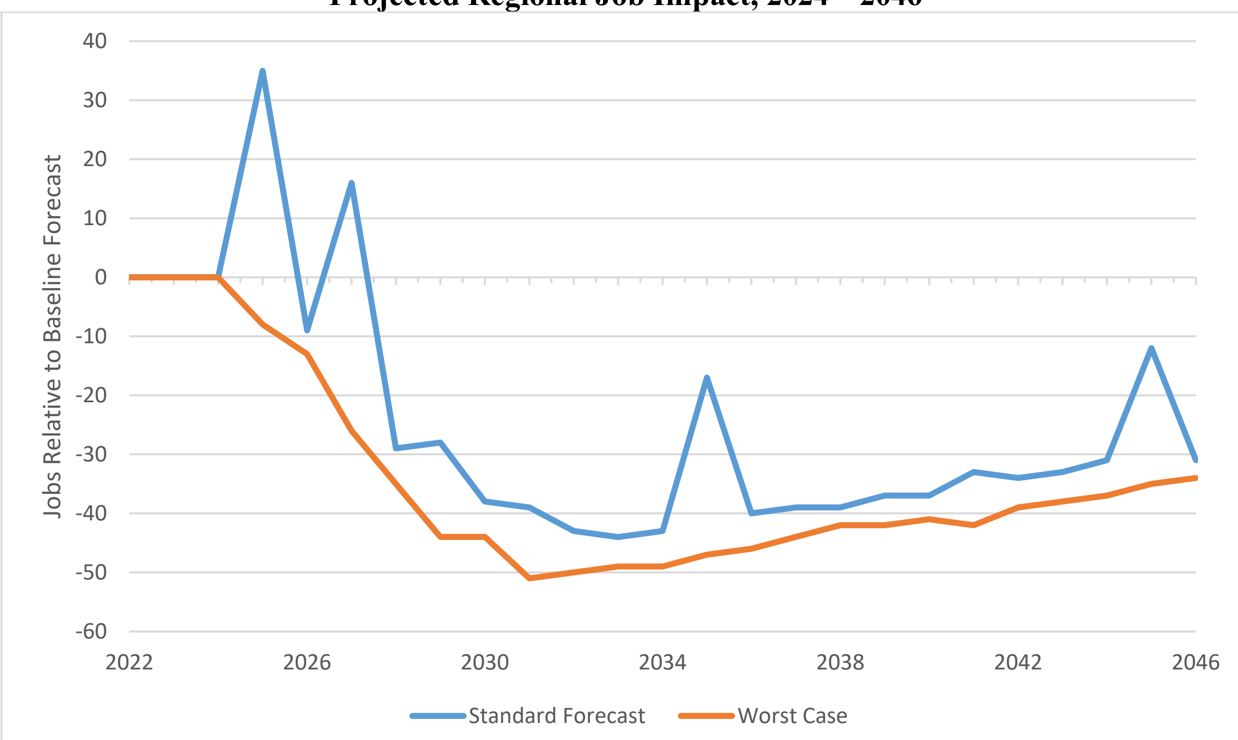
**Table 4**
**Projected Job Impact of PAR 1148.1 for Selected Industries and Years**

| Industry (NAICS) | 2025 | 2027 | 2033 | 2040 | 2046 | Annual Average (2025-2046) | Baseline Number of Jobs (Average, 2024-2046) | Percent Relative to Baseline |
|---|---|---|---|---|---|---|---|---|
| **Construction (23)** | 3 | -3 | -12 | -6 | -4 | -7 | 514,757 | 0.0014% |
| **Professional, Scientific and Technical Services (54)** | 2 | 0 | -5 | -6 | -5 | -4 | 967,340 | 0.0004% |
| **Oil and Gas Extraction (211)** | -1 | -2 | -5 | -4 | -3 | -4 | 2,769 | 0.1445% |
| **State and Local Government (92)** | 1 | 1 | -5 | -5 | -4 | -3 | 948,156 | 0.0003% |
| **Retail Trade (44-45)** | 2 | 1 | -3 | -3 | -3 | -2 | 805,513 | 0.0002% |
| **Administrative and Support Services (561)** | 2 | 1 | -3 | -3 | -3 | -2 | 816,654 | 0.0002% |
| **Primary Metal Manufacturing (331)** | 0 | 1 | 0 | 0 | 0 | 0 | 13,132 | 0% |
| **Motor Vehicles, Bodies and Trailers, and Parts Manufacturing (3361-3363)** | 0 | 5 | 0 | 0 | 0 | 0 | 9,034 | 0% |
| **Computer and Product Manufacturing (334)** | 16 | 0 | 0 | 0 | 0 | 2 | 119,459 | 0.0017% |
| **Repair and Maintenance (811)** | 0 | 5 | 3 | 2 | 2 | 3 | 120,046 | 0.0024% |
| **Other Industries** | 10 | 8 | -14 | -12 | -11 | -9 | 7,130,286 | 0.0002% |
| **All Industries** | **35** | **16** | **-44** | **-37** | **-31** | **-28** | **11,447,145** | **0.0002%** |

Note: Totals may not sum due to rounding.

In addition, in 2013, South Coast AQMD contracted with Abt Associates Inc. to review the South Coast AQMD socioeconomic assessments for Air Quality Management Plans and individual rules with the goal of providing recommendations that could enhance South Coast AQMD's socioeconomic analyses. In 2014, Abt Associates Inc. published a report which included a recommendation for South Coast AQMD to enhance socioeconomic analyses by testing major assumptions through conducting a scenario analysis. As such, South Coast AQMD generally includes an alternative worst-case scenario in Socioeconomic Impact Assessments which analyzes a scenario that assumes the affected facilities would purchase all feasible monitoring equipment and services from providers located outside of the South Coast AQMD's jurisdiction.[9] In short, this alternative worst-case scenario only models the impacts of the costs of compliance with the proposed amended rule and excludes any market benefits associated with revenue realized by service providers in the four-county region. This also excludes benefits derived from the wages earned by employees performing OGI inspections. This hypothetical scenario is designed to test the sensitivity of the REMI analysis to the assumptions regarding how compliance costs and revenues would be distributed inside and outside of South Coast AQMD's jurisdiction. In practice, however, materials and labor for installation are more likely to be provided by local suppliers. As shown in Figure 2, this worst-case scenario would result in an annual average of approximately 39 jobs foregone relative to the baseline scenario. However, the job impact can be considered as minimal since the 39 jobs foregone only represent 0.0003% of the average forecasted baseline jobs in the regional economy.

**Figure 2**
**Projected Regional Job Impact, 2024 – 2046**




[9] Abt Associates Inc., August 2014, Review of the SCAQMD Socioeconomic Impact Assessment Chapter 6, Section 3, https://www.aqmd.gov/docs/default-source/Agendas/aqmp/scaqmd-report---review-socioeconomic-assessments.pdf, accessed July 16, 2024.

**Price Impact and Competitiveness**

The impact of PAR 1148.1 on production costs and delivered prices in the South Coast AQMD region is not expected to be substantial. According to the REMI Model, PAR 1148.1 is projected to increase the relative delivered price of products in the industry of Oil and Gas Extraction (NAICS 211) by 0.02% in the year 2027 and will have even smaller increases in that industry over the remainder of the forecast period. Similarly, the relative cost of production in the industry of Oil and Gas Extraction is expected to increase by 0.44% in 2027 and will see even smaller increases in the industry throughout the remainder of the forecasted period. Given the minimal potential increase in delivered prices and cost of production, PAR 1148.1 is not expected to affect the ability of firms to compete with producers located outside of South Coast AQMD's jurisdiction.

## REFERENCES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# Proposed Amended Rule 1148.1 - Oil and Gas Production Wells

Board Meeting
August 2, 2024

# Rule 1148.1 Regulatory History

Adopted on March 5, 2004

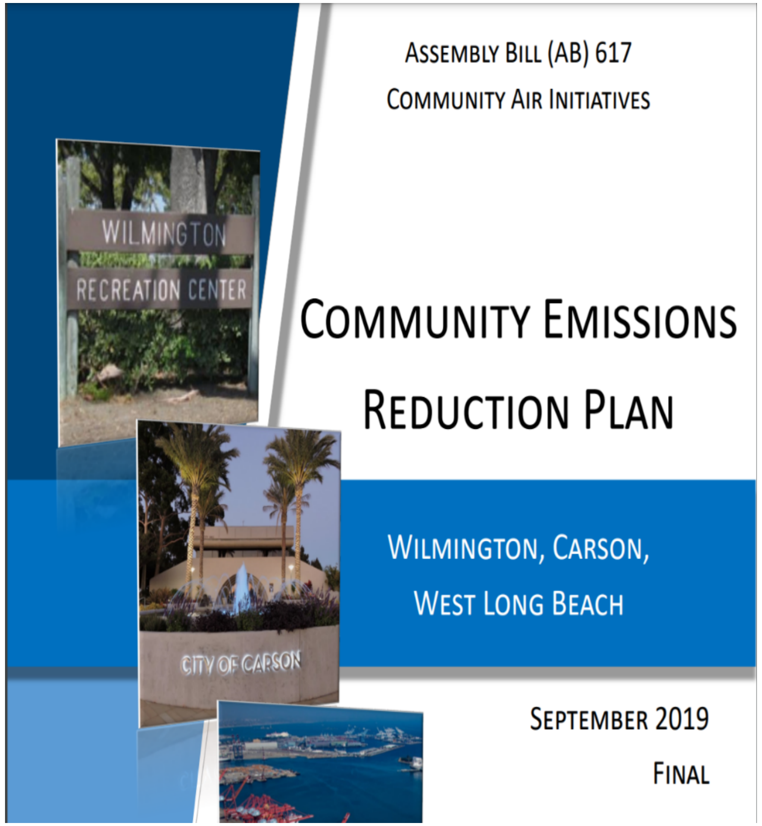
Purpose: Reduce VOC emissions from wellheads, well cellars, and handling of produced gas

Applicable to onshore oil producing wells, well cellars and produced gas handling operation and associated maintenance activities

Approximately 80 companies representing 330 sites are regulated by this rule

# AB 617 and Community Emission Reduction Plans

- Two AB 617 communities identified oil and gas production emissions as objectives in their Community Emission Reduction Plans (CERP)
  - Wilmington, Carson, West Long Beach (WCWLB)
  - South Los Angeles (SLA)
- Staff worked with AB 617 community stakeholders and the regulated industry through a public process
  - Multiple site visits conducted to address key issues brought by stakeholders
- PAR 1148.1 also partially implements the 2022 Air Quality Management Plan control measure FUG-01: *Improved Leak Detection and Repair*
- Staff is not aware of any remaining key issues



# Summary of Key Proposals

Monthly use of Optical Gas Imaging (OGI) for enhanced leak detection

Use of Tier 4 Final diesel engines on workover rigs

Notification for quantified leaks > 25,000 ppm

Establish NOx limits for combustion equipment

Ban the use of odorants and limit air toxics in odor neutralizers

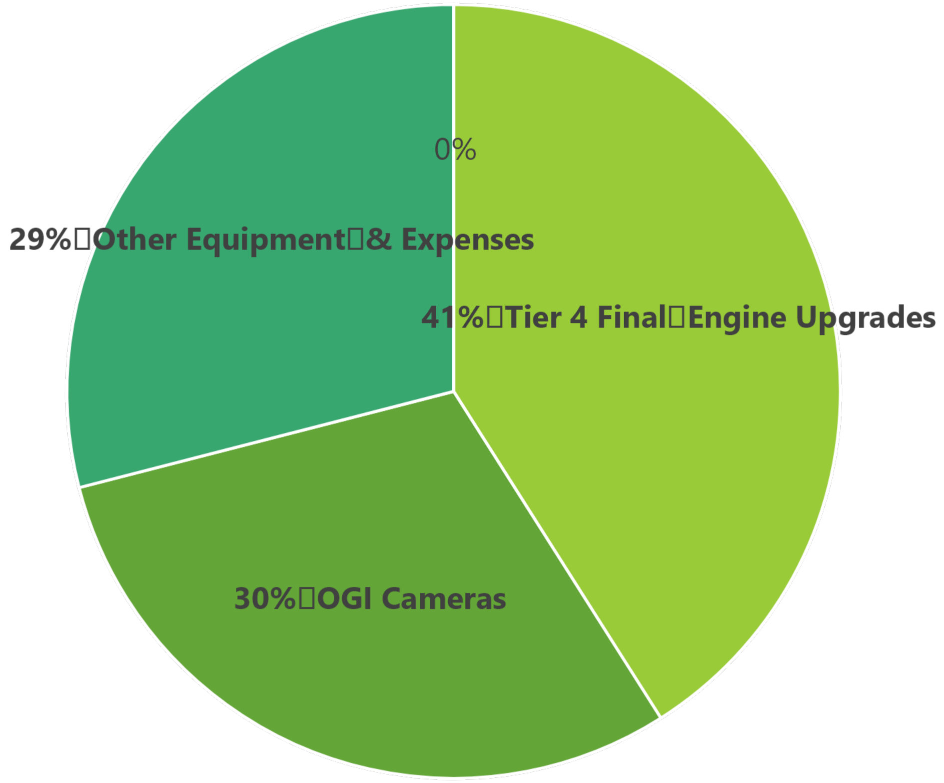
# Emission Reductions & Cost-Effectiveness

| Proposed Measure | Emission Reductions (tons/day) | Annual Cost ($) | Cost-Effectiveness ($/ton reduced) |
|---|---|---|---|
| Enhanced Leak Detection | 0.27 VOC | $1,369,000 | $13,800 |
| NOx Limits for Combustion Equipment | 0.005 NOx | $4,600 to $56,100 | $7,000 to $30,700 |
| Tier 4 Final Workover Rigs | 0.51 NOx | $2,544,000 | $13,700 |
| Ban of Odorant Use | N/A | N/A | N/A |
| Leak Notification | N/A | N/A | N/A |

# Socioeconomic Impact Assessment and California Environmental Quality Act (CEQA)

- Compliance Costs
  - Average annual cost ranges from ~$4.1 million to ~$4.7 million using a real interest rate from 1% to 4%, respectively
- Job Impacts
  - 28 jobs foregone annually on average from 2025 - 2046
- CEQA
  - Proposed project involves minimal to no construction activities
  - No significant adverse environmental impacts are expected
  - A Notice of Exemption has been prepared

**Total Annual Estimated Cost % by Expense Category**



# Staff Recommendation

Adopt resolution:

- Determining that PAR 1148.1 is exempt from the requirements of CEQA
- Amending Rule 1148.1