BOARD MEETING DATE: April 5, 2024 AGENDA NO. 29

PROPOSAL: Determine That Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares, Is Exempt from CEQA; and Amend Rule 1118

SYNOPSIS: Proposed Amended Rule 1118 (PAR 1118) seeks further control and reduction of flaring and flare related emissions at refineries, hydrogen production plants, and sulfur recovery plants and establishes new requirements to monitor and record flaring data. PAR 1118 will reduce emissions from refinery flares by lowering the sulfur dioxide performance target for general service flares, establish a new NOx performance target for hydrogen production plants, and establish a throughput threshold for clean service flares. PAR 1118 will also increase mitigation fees and fulfill the Assembly Bill 617 Wilmington, Carson, West Long Beach Community Emission Reduction Plan air quality commitment objectives related to refinery flaring.

COMMITTEE: Stationary Source, February 16, 2024; Recommended for Approval

RECOMMENDED ACTIONS:
Adopt the attached Resolution:

1. Determining that Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares, is exempt from the requirements of the California Environmental Quality Act; and
2. Amending Rule 1118.

Wayne Nastri
Executive Officer

SN:SR:MK:HF:SK:ZB:ST

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**Background**

Rule 1118 – Control of Emissions from Refinery Flares (Rule 1118) was adopted on February 13, 1998, and established requirements for flares operated at petroleum refineries and related operations. The intent of Rule 1118 is to monitor and record data on refinery and related flaring operations, and to control and minimize flaring and flare-related emissions. There are 12 facilities including eight petroleum refining facilities, three hydrogen production plants, and one sulfur recovery plant, with a total of 31 existing flares subject to Rule 1118. The last major amendment to Rule 1118 was the 2017 amendment, which was the first phase of a planned two-phase amendment. The first phase primarily focused on establishing mechanisms to gather more information through scoping documents prepared by the regulated facilities. The Assembly Bill 617 (AB 617) Community Emission Reductions Plan (CERP) for Wilmington, Carson, West Long Beach (WCWLB) includes seven air quality objectives to reduce emissions from refinery flaring. There are eight facilities in the WCWLB community including five petroleum refining facilities, two hydrogen production plants, and one sulfur recovery plant, with a total of 20 flares.

**Public Process**

PAR 1118 was developed through a public process. Staff held five Working Group Meetings on: July 21, 2022, October 26, 2022, April 26, 2023, October 25, 2023, and December 12, 2023, and an evening community meeting held on February 16, 2024. The meetings included a variety of stakeholders such as affected facilities, industry associations, equipment vendors, public agencies, and environmental and community groups. In addition, staff held a Public Workshop on February 8, 2024. As part of this rule development process, staff also met with individual stakeholders and conducted site visits at all affected facilities.

**Proposed Amendments**

PAR 1118 is the second phase of the planned two-phase rule amendment and seeks to achieve further emission reductions from refinery flares and aligns Rule 1118 with requirements of U.S. EPA's Refinery Sector Rule for flares. PAR 1118 relies upon the information gathered from the scoping documents submitted after the 2017 amendment and staff's investigations on flare emission reductions. PAR 1118 will achieve four out of the seven AB 617 CERP air quality objectives for WCWLB community by establishing a more stringent sulfur dioxide ($SO_2$) performance target, a new performance target for NOx emissions from flares at hydrogen production plants, and a throughput threshold for liquified petroleum gas flares at refineries. PAR 1118 will not address the AB 617 CERP air quality objectives for WCWLB community with respect to: 1) storing the recovered vent gas by vapor recovery system during shutdowns, which is not deemed feasible due to safety concerns regarding storing large volumes of gas that can create an explosive environment; 2) modifications to flare headers for gas diversion, as modifications to flare headers was implemented as part of the requirements by 2005 amendments to Rule 1118; and 3) using remote optical sensing technology for flare emission characterization, which is currently under review by U.S. EPA and has not been approved at this time. PAR 1118 is estimated to achieve more than 50 percent reduction in $SO_2$ emissions, fulfilling the $SO_2$ emission objective of AB 617 CERP for WCWLB community. PAR 1118 also clarifies and updates rule language, restructures the rule, removes obsolete language, and updates requirements for notifications and reporting sent through Flare Event Notification System.

**Emission Reductions**

PAR 1118 will affect 12 facilities located in Los Angeles County. This includes eight petroleum refining facilities, three hydrogen production plants, and one sulfur recovery plant with a total of 31 existing flares. PAR 1118 is expected to reduce $SO_2$ by 16.6 tons per year, VOC by 3.8 tons per year, and NOx by 10.1 tons per year. In addition, $SO_2$ is a precursor to the formation of PM2.5; therefore, the $SO_2$ emission reductions will result in approximately 3.3 tons of PM2.5 reduced per year.

**Key Issues**

Throughout the rule development process, staff worked with stakeholders to address and resolve key issues. There are two remaining key issues: 1) The stringency of the $SO_2$ performance standard; and 2) The lack of a VOC performance target.

1) *More Stringent $SO_2$ Performance Target*

PAR 1118 lowers the existing $SO_2$ performance target from 0.5 to 0.25 ton per million barrels of processing capacity; stakeholders requested a more stringent $SO_2$ performance target of 0.1 ton per million barrels of procession capacity.

Staff's proposed lower performance target is estimated to achieve 51 percent reduction in $SO_2$ emissions from flaring in WCWLB community. This reduction aligns with the AB 617 CERP objectives for WCWLB community and reflects collaborative efforts with the Community Steering Committee which prioritized a 50 percent reduction in $SO_2$ emissions from flaring.

While WCWLB CERP aimed for 50-percent reduction in the $SO_2$ emissions, staff conducted a technical feasibility evaluation for all facilities, considering the possibility of 80 percent reduction of the $SO_2$ performance target (0.1 ton of $SO_2$ per million barrels of processing capacity). This evaluation concluded that achieving the lower target would require the installation of significant additional control systems. Facilities meeting the $SO_2$ performance level of 0.1 ton per million barrel of processing capacity are equipped with multiple gas turbine cogeneration units and a flare gas recovery system capable of diverting recovered vent gas from the flare system to the gas turbine cogeneration units. Staff evaluated the technical feasibility and cost-effectiveness of requiring all facilities to install similar systems; however, staff determined it not be cost-effective ($1.6 million per ton of $SO_2$ reduced). Staff's proposed $SO_2$ performance target of 0.25 ton per million barrels of processing capacity is expected to be achieved through process changes and implementing some flare minimization projects to ensure the facility can consistently maintain lower flare emissions.

2) *VOC Performance Target*

Stakeholders recommended the addition of a VOC performance target to PAR 1118.

Staff is proposing to reduce the $SO_2$ performance target to 0.25 ton per million barrels of processing capacity, which will lead to concurrent reductions in VOC and NOx emissions, both of which serve as precursors for ozone. These reductions are crucial in the South Coast Air Basin, which is classified as an extreme non-attainment area for ozone. While VOC contributes to ozone, NOx is identified as the primary driver for ozone in the region. Moreover, refinery flares are required to achieve at least 98 percent destruction efficiency for VOC emissions.

Staff acknowledges some flare events have higher levels of VOC emissions compared to $SO_2$; however, the performance targets are based on annual emissions. A review of the past 12-years of annual flare emissions shows higher $SO_2$ emissions than VOC emissions which supports staff's conclusion that the $SO_2$ performance target is the most effective mechanism to achieve reductions in both $SO_2$ and VOC emissions. The proposed $SO_2$ performance target of 0.25 ton per million barrels of processing capacity is estimated to concurrently achieve 3.3 ton of VOC reductions per year on average (based on VOC baseline emissions in 2019). In addition, PAR 1118 includes a new throughput limit to reduce NOx emissions from flares that combust liquid petroleum gas which concurrently will achieve 0.5 ton of VOC reductions per year on average (based on VOC baseline emissions in 2019) for an overall VOC reduction of 3.8 tons per year from PAR 1118.

**California Environmental Quality Act**

Pursuant to the California Environmental Quality Act (CEQA) Guidelines Section 15002(k) and 15061, the proposed project (PAR 1118) 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 of this Board Letter. 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, and with the State Clearinghouse of the Governor's Office of Planning and Research.

**Socioeconomic Impact Assessment**

PAR 1118 will be applicable to 12 facilities with 31 flares, but only five of the 12 affected facilities are anticipated to incur quantifiable compliance costs associated with the following installations of: 1) continuous flow meters on three flares; 2) one refrigeration/chiller for one flare; and 3) replacement of an existing flare system with one new flare system. The parent companies of the five affected facilities do not qualify as small businesses. The annual average compliance cost of the five affected facilities is estimated to be $381,677 and $722,904 at a one-percent and a four-percent interest rate, respectively.

The jobs and other regional economic impacts of PAR 1118 are expected to be minimal. The details of the Socioeconomic Impact Assessment can be found in Chapter 5 of the Final Staff Report (Attachment G to this Board Letter).

**AQMP and Legal Mandates**
Health and Safety Code Section 40460(a) requires South Coast AQMD to adopt an AQMP to meet state and federal ambient air quality standards in the South Coast Air Basin. In addition, the Health and Safety Code requires South Coast AQMD to adopt rules and regulations that carry out the objectives of the AQMP. The proposed amendments are not the result of an AQMP control measure but are needed to satisfy the commitment in the resolution from the 2017 amendment of Rule 1118 and to achieve the objectives that were set forth by the AB617 CERP for WCWLB community.

**Resource Impacts**
Existing staff resources are adequate to implement the proposed amended rule. PAR 1118 includes updates and new requirements to the Flare Event Notification System that will involve further collaboration between staff and stakeholders to develop through a public process.

**Attachments**
A. Summary of Proposal
B. Key Issues and Responses
C. Rule Development Process
D. Key Contacts List
E. Resolution
F. Proposed Amended Rule 1118
G. Final Staff Report
H. Notice of Exemption from CEQA
I. Board Presentation

**ATTACHMENT A**

**SUMMARY OF PROPOSAL**

## Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

Purpose

- Separates Purpose and Applicability to be consistent with recently adopted and amended rules by South Coast AQMD

Definitions

- Adds new definitions including:
  - Alternative Feedstock, Facility, Flare Monitoring and Recording Plan, Hydrogen Production Capacity, Oxides of Nitrogen ($NO_x$) Emissions, Performance Target, Processing Capacity, Refine, Relative Clause, and Unplanned Flare Events
- Updates definitions including:
  - Essential Operational Need, Flare, Flare Event, Flare Event Notification System, Flare Tip Velocity, Planned Flare Event, and Refinery
- Removes the following definition:
  - Notice of Sulfur Dioxide Exceedance

Requirements

- Moves all provisions and requirements related to submission of specific cause analysis and corrective actions implementation schedule to a new subdivision

Specific Cause Analysis

- Provisions for facilities to conduct single specific cause analysis for specific flare events
- Incorporates U.S. EPA Refinery Sector Rule provisions into PAR 1118

Performance Targets and Annual Throughput Limit:

- Establishes $SO_2$ performance target to gradually decrease over time:
  - 2024-2025: 0.50 ton of sulfur dioxide per million barrels of processing capacity (current performance target)
  - 2026-2028: 0.35 ton of sulfur dioxide per million barrels of processing capacity
  - 2029 and afterward: 0.25 ton of sulfur dioxide per million barrels of processing capacity

**Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares**

- Establishes a NOx performance target at Hydrogen Plants of 0.3 pound of NOx per hydrogen production capacity
- Establishes an annual throughput limit with total heat content of 15,000 MMBtu per year for non-hydrogen clean service flares

Reporting

- Requires reporting $SO_2$ emissions for all flares, NOx emissions for hydrogen clean service flares, and annual throughput for non-hydrogen clean service flares for any calendar year where the applicable target/threshold was exceeded
- Requires submitting monthly reports of flare events data in an electronic format
- Requires submitting specific cause analysis reports in an electronic format
- Requires facilities with no publicly available processing capacity to report their processing capacity to the Executive Officer within 30 days of the end of every calendar year

Monitoring and Recordkeeping

- Adds requirements for the replacement of any on/off flow meters for general and hydrogen clean service flares
- Requires retainment of records of the relative cause analysis

Exemptions

- Adds “water curtailment" to the considerations for exemption of flare events caused by external events beyond the operator’s control, natural disasters, or act of war or terrorism, from calculations of $SO_2$ performance target
    - Similar considerations for the new NOx performance target
    - Similar considerations for annual throughput

Attachment A – Flare Monitoring System Requirements

- Allows facilities to postpone the required calibration of monitoring systems for up to 72 hours during an ongoing flare event

Attachment B – Guidelines for Calculating Flare Emissions

- Adds provision to allow missing data to be substituted with data recorded one hour before and one hour after the period that data is not recorded, if the missing data event lasts 15 minutes or less

**Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares**

Attachment C – Processing Capacity of Refineries and Production Capacity of Hydrogen Production Plants

- New attachment added to list the updated processing capacity for refineries and production capacity for hydrogen production plants

Attachment D – Guidelines for Calculating Mitigations Fees for Performance Targets Exceedance

- New attachment added to provide guidelines for calculating:
  - Facility specific $SO_2$ performance target for a refinery,
  - NOx performance target for hydrogen production plants, and
  - Mitigation fees adjusted based on consumer price index

## ATTACHMENT B

## KEY ISSUES AND RESPONSES

| Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares |
|---|
| Throughout the rule development process, staff worked with stakeholders to address and resolve key issues. Stakeholders have expressed concerns about two key issues: 1) The stringency of the $SO_2$ performance standard; and 2) The lack of a VOC performance target.<br><br>*1) More Stringent $SO_2$ Performance Target*<br><br>PAR 1118 lowers the existing $SO_2$ performance target from 0.5 to 0.25 ton per million barrels of processing capacity; stakeholders requested a more stringent $SO_2$ performance target of 0.1 ton per million barrels of procession capacity.<br><br>Staff's proposed lower performance target is estimated to achieve 51 percent reduction in $SO_2$ emissions from flaring in WCWLB community. This reduction aligns with the AB 617 CERP objectives for WCWLB community and reflects collaborative efforts with the Community Steering Committee which prioritized a 50-percent reduction in $SO_2$ emissions from flaring.<br><br>While WCWLB CERP aimed for 50 percent reduction in the $SO_2$ emissions, staff conducted a technical feasibility evaluation for all facilities, considering the possibility of 80 percent reduction of the $SO_2$ performance target (0.1 ton of $SO_2$ per million barrels of processing capacity). This evaluation concluded that achieving the lower target would require the installation of significant additional control systems. Facilities meeting the $SO_2$ performance level of 0.1 ton per million barrel of processing capacity are equipped with multiple gas turbine cogeneration units and a flare gas recovery system capable of diverting recovered vent gas from the flare system to the gas turbine cogeneration units. Staff evaluated the technical feasibility and cost-effectiveness of requiring all facilities to install similar systems; however, staff determined it not be cost-effective ($1.6 million per ton of $SO_2$ reduced). Staff's proposed $SO_2$ performance target of 0.25 ton per million barrels of processing capacity is expected to be achieved through process changes and implementing some flare minimization projects to ensure the facility can consistently maintain lower flare emissions.<br><br>*2) VOC Performance Target*<br><br>Stakeholders recommended the addition of a VOC performance target to PAR 1118.<br><br>Staff is proposing to reduce the $SO_2$ performance target to 0.25 ton per million barrels of processing capacity, which will lead to concurrent reductions in VOC and NOx emissions, both of which serve as precursors for ozone. These reductions are crucial in |

the South Coast Air Basin, which is classified as an extreme non-attainment area for ozone. While VOC contributes to ozone, NOx is identified as the primary driver for ozone in the region. Moreover, refinery flares are required to achieve at least 98 percent destruction efficiency for VOC emissions.

Staff acknowledges some flare events have higher levels of VOC emissions compared to $SO_2$; however, the performance targets are based on annual emissions. A review of the past 12-years of annual flare emissions shows higher $SO_2$ emissions than VOC emissions which supports staff's conclusion that the $SO_2$ performance target is the most effective mechanism to achieve reductions in both $SO_2$ and VOC emissions. The proposed $SO_2$ performance target of 0.25 ton per million barrels of processing capacity is estimated to concurrently achieve 3.3 ton of VOC reductions per year on average (based on VOC baseline emissions in 2019). In addition, PAR 1118 includes a new throughput limit to reduce NOx emissions from flares that combust liquid petroleum gas which concurrently will achieve 0.5 ton of VOC reductions per year on average (based on VOC baseline emissions in 2019) for an overall VOC reduction of 3.8 tons per year from PAR 1118.

**ATTACHMENT C**

**RULE DEVELOPMENT PROCESS**

**Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares**

**Initiated Rule Development**
July 2022

**Working Group Meetings (5)**
July 21, 2022
October 26, 2022
April 26, 2023
October 25, 2023
December 12, 2023

**75-Day Notice of Public Workshop**
January 19, 2024

**Public Workshop**
February 8, 2024

**Stationary Source Committee Meeting**
February 16, 2024

**Evening Community Meeting with Spanish Translation**
February 16, 2024

**Set Hearing**
March 1, 2024

**30-Day Notice of Public Hearing**
March 5, 2024

**Public Hearing**
April 5, 2024

**Twenty-one (21) months spent in rule development**
**Five (5) Working Group Meetings**
**One (1) Public Workshops**
**One (1) Stationary Source Committee Meeting**
**One (1) Community Focused Evening Meeting**

## ATTACHMENT D

## KEY CONTACTS LIST

### Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

**Facilities**

- Air Liquide Large Industries U.S., LP
- Air Products and Chemical, Inc.
- AltAir Paramount
- Chevron Products Co.
- Marathon Petroleum Corporation
- Phillips 66 Company
- Torrance Refining Company
- Ultramar Inc.

**Associations or Entities**

- Ramboll
- Western States Petroleum Association
- Regulatory Flexibility Group

**Government Agencies**

- California Air Resources Board
- Southern California Association of Governments
- U.S. Environmental Protection Agency

**Other Interested Parties**

- California Council for Environmental and Economic Balance
- Coalition for Clean Air
- Communities for a Better Environment
- Earthjustice
- East Yard Communities
- R.A. Nichols Engineering
- Sierra Club
- Providence Photonics
- Zeeco

**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 1118 – Control of Emissions from Refinery Flares is exempt from the requirements of the California Environmental Quality Act (CEQA).**

**A Resolution of the South Coast AQMD Governing Board amending Rule 1118 – Control of Emissions from Refinery Flares.**

**WHEREAS**, the South Coast AQMD Governing Board finds and determines that Proposed Amended Rule 1118 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 the proposed project is exempt from CEQA; and

**WHEREAS**, the South Coast AQMD Governing Board finds and determines that because the anticipated physical changes that may occur as a result of implementing the proposed project indicates that the construction activities and associated emissions are expected to be minimal, it can be seen with certainty that Proposed Amended Rule 1118 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**, Proposed Amended Rule 1118 and supporting documentation, including but not limited to, the Notice of Exemption and the Final Staff Report which includes a 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 (Section 30.5(4)(D)(i) of the Administrative Code), that no modifications have been made to the proposed project since notice of Public Hearing was published that are so substantial as to significantly affect the meaning of Proposed Amended Rule 1118 within the meaning of Health and Safety Code Section 40726 because: 1) moving "; and" from subparagraph (d)(3)(B) to subparagraph (d)(3)(A) was to correct a typo; 2) the addition of "and" to subparagraph (f)(1)(A) was for clarification; and 3) the deletion of "the" from subparagraphs (j)(16)(A), (j)(16)(B), (j)(16)(C), and (j)(16)(D) was made for consistency purposes; and: (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**, 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 1118 to further control and minimize flaring and flare-related emissions from flares operated at petroleum refineries and related operations, to fulfill the resolution from the 2017 rule amendment, and to implement the objectives of Assembly Bill 617 Community Emissions Reduction Plan for the Wilmington, Carson, West Long Beach community to reduce emissions from flares at facilities covered by Rule 1118; and

**WHEREAS**, the South Coast AQMD Governing Board obtains its authority to adopt, amend or repeal rules and regulations from Sections 39002, 40000, 40001, 40440, 40441, 40702, and 40725 through 40728 of the Health and Safety Code; and

**WHEREAS**, the South Coast AQMD Governing Board has determined that Rule 1118, as proposed to be amended, is written or displayed so that its meaning can be easily understood by the persons directly affected by it; and

**WHEREAS**, the South Coast AQMD Governing Board has determined that Rule 1118, as proposed to be amended, is in harmony with, and not in conflict with or contradictory to, existing statutes, court decision, or state or federal regulations; and

**WHEREAS**, the South Coast AQMD Governing Board has determined that Rule 1118, as proposed to be amended, 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 1118, references the following statutes which the South Coast AQMD hereby implements, interprets, or makes specific: Health and Safety Code Sections 39002, 40001, 40702, 40440(a), 40725 through 40728.5, and federal Clean Air Act Sections 110, 172, and 182(e); 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 that the South Coast AQMD's comparative analysis of Proposed Amended Rule 1118 is included in the Final Staff Report; and

**WHEREAS,** the South Coast AQMD Governing Board has determined that the Socioeconomic Impact Assessment, as presented in the Final Staff Report, is consistent with the March 17, 1989 Governing Board Socioeconomic Resolution for rule adoption; and

**WHEREAS,** the South Coast AQMD Governing Board has determined that the Socioeconomic Impact Assessment, as presented in the Final Staff Report, is consistent with the provisions of Health and Safety Code Sections 40440.8 and 40728.5; and

**WHEREAS,** the South Coast AQMD Governing Board has determined that Proposed Amended Rule 1118 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 Socioeconomic Impact Assessment, as presented in the Final Staff Report; and

**WHEREAS,** the South Coast AQMD Governing Board has actively considered the Socioeconomic Impact Assessment, as presented in the Final Staff Report, and has made a good faith effort to minimize such impacts; and

**WHEREAS**, the South Coast AQMD staff conducted a Public Workshop regarding Proposed Amended Rule 1118 on February 8, 2024; 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 1118 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

**WHEREAS**, Proposed Amended Rule 1118 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

**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 1118 is exempt from CEQA pursuant to CEQA Guidelines

Section 15061(b)(3) – Common Sense Exemption. This information was presented to the South Coast AQMD Governing Board, whose members exercised their independent judgement and reviewed, considered, and approved the information therein prior to acting on the proposed project; and

**BE IT FURTHER RESOLVED,** the South Coast AQMD Governing Board directs the South Coast AQMD to limit use of mitigation fees collected from an exceedance of an $SO_2$ performance target to funding PM or $SO_2$ reduction projects and to limit the use of mitigation fees collected from an exceedance of a NOx performance target to funding PM or NOx reduction projects; 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 1118 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 1118 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 1118 to CARB for approval and subsequent submittal to U.S. EPA for inclusion into the State Implementation Plan.

DATE:______________________ ____________________________

CLERK OF THE BOARDS

(Adopted February 13, 1998)(Amended November 4, 2005)(Amended July 7, 2017)
(Amended January 6, 2023)(Amended [*DATE OF RULE ADOPTION*])

[*RULE INDEX TO BE ADDED AFTER RULE ADOPTION*]

**PROPOSED AMENDED RULE 1118. CONTROL OF EMISSIONS FROM REFINERY FLARES**

(a) Purpose ~~and Applicability~~

The purpose of ~~Rule 1118~~ this rule is to monitor and record data on ~~refinery~~ Refinery and related flaring operations, and to control and minimize flaring and ~~flare~~ Flare-related emissions. The provisions of this rule are not intended to preempt the operations and practices of any ~~petroleum refinery~~ Refinery, ~~sulfur recovery plant~~ Sulfur Recovery Plant, ~~and~~ or ~~hydrogen production plant~~ Hydrogen Production Plant ~~operations and practices~~ with regard to safety. ~~This rule applies to all flares used at petroleum refineries, sulfur recovery plants and hydrogen production plants.~~

(b) Applicability

This rule applies to all Flares used at Refineries, Sulfur Recovery Plants, and Hydrogen Production Plants.

~~(b)~~(c) Definitions

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

(1) ALTERNATIVE FEEDSTOCK is any feedstock, intermediate, product, or byproduct material containing organic material that is not derived from crude oil product, coal, natural gas, or any other fossil-fuel based organic material.

~~(1)~~(2) CLEAN SERVICE STREAM is a gas stream such as ~~natural gas~~ Natural Gas, hydrogen gas, and/or liquefied petroleum gas. Other gases with a fixed composition that inherently have a low sulfur content and are vented from specific equipment may be classified as ~~clean service streams~~ Clean Service Streams, if determined to be equivalent and approved in writing by the Executive Officer.

~~(2)~~(3) EMERGENCY is a condition beyond the reasonable control of the owner or operator of a ~~flare~~ Flare requiring immediate corrective action to restore normal and safe operation, which is caused by a sudden, infrequent and not reasonably preventable equipment failure, upset condition, equipment malfunction or breakdown, electrical power failure, steam failure, cooling air or water failure, instrument air failure, reflux failure, heat exchanger tube failure, loss of heat, excess heat, fire and explosion, natural disaster, act of war or terrorism, or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility. ~~For the purpose of this rule, a flare event~~ A Flare Event caused by poor maintenance, or a condition caused by operator error, ~~that results in a flare event~~ shall not be deemed an ~~emergency~~ Emergency.

~~(3)~~(4) ESSENTIAL OPERATIONAL NEED is an activity other than resulting from poor maintenance or operator error, determined by the Executive Officer to meet one of the following:

(A) Temporary fuel gas system imbalance due to:

(i) Inability to accept gas compliant with Rule 431.1 – Sulfur Content of Gaseous Fuels (Rule 431.1) by an electric generation unit at the ~~facility~~ Facility that produces electricity to be used in a state grid system~~,~~; or

(ii) Inability to accept gas compliant with Rule 431.1 by a third party that has a contractual gas purchase agreement with the ~~facility~~ Facility;~~,~~ or

(iii) The sudden ~~shutdown~~ Shutdown of a refinery fuel gas combustion device that is not due to an ~~emergency~~ Emergency or breakdown;

(B) Venting of streams that cannot be recovered due to incompatibility with recovery system equipment or with refinery fuel gas systems, including supplemental ~~natural gas~~ Natural Gas or other gas compliant with Rule 431.1 that is used for the purpose of maintaining the higher heating value of the ~~vent gas~~ Vent Gas above 300 British Thermal Units (Btu) per standard cubic foot. Such streams include inert gases, oxygen, gases with low or high molecular weights outside the design operating range of the recovery system equipment and gases with low or high higher heating values that could render refinery fuel gas systems and/or combustion devices unsafe; or

(C) Venting of ~~clean service streams~~ Clean Service Streams to a ~~clean service flare~~ Hydrogen Clean Service Flare, Non-Hydrogen Clean

Service Flare, or ~~a general service flare~~ General Service Flare. Venting of Clean Service Streams to a Non-Hydrogen Clean Service Flare being operated at a level above the annual throughput in subdivision (g) shall not be considered an Essential Operational Need after the effective dates in paragraph (g)(2).

(5) FACILITY is any Refinery, Sulfur Recovery Plant, or Hydrogen Production Plant.

~~(4)~~(6) FLARE is a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. When used as a verb, Flare means the combustion of ~~vent gases~~ Vent Gas in a ~~flare~~ Flare ~~device~~. ~~Based on their use, flares~~ Flares are classified based on their use and include:

~~(A) CLEAN SERVICE FLARE is a flare that is designed and configured by installation to combust only clean service streams.~~

~~(B)~~(A) GENERAL SERVICE FLARE ~~is a flare~~ that is not a Hydrogen Clean Service Flare or Non-Hydrogen Clean Service Flare;~~.~~

(B) HYDROGEN CLEAN SERVICE FLARE that is designed and configured by installation to combust only Clean Service Streams from a Hydrogen Production Plant; or

(C) NON-HYDROGEN CLEAN SERVICE FLARE that is designed and configured by installation to combust only Clean Service Streams from a Facility other than Hydrogen Production Plant.

~~(5)~~(7) FLARE EVENT is any ~~intentional or unintentional~~ planned or unplanned combustion of ~~vent gas~~ Vent Gas in a ~~flare~~ Flare or Flares. ~~The start is determined by the vent gas flow velocity exceeding 0.10 feet per second and the end is determined when the vent gas flow velocity drops below 0.12 feet per second, or when the owner or operator can demonstrate that no more vent gas was combusted based upon the monitoring records of the flare water seal level and/or other parameters as approved by the Executive Officer in the Flare Monitoring and Recording Plan as described in subdivision (f). For flare events that can be attributed to the same process unit(s) or equipment and has more than one start and end within a 24 hour period, it shall be considered a continuation of the same event, and not a separate or unique event. For a flare event that continues for more than 24 hours, each calendar day of venting of gases shall constitute a flare event.~~

(8) FLARE EVENT NOTIFICATION SYSTEM (FENS) is a web-based system that allows facilities to notify South Coast AQMD about Flare Events and to enter information such as the time that flaring begins and ends, Vent Gas flow rates, and emissions.

~~(6)~~(9) FLARE GAS RECOVERY SYSTEM is a system ~~comprised of compressors, pumps, heat exchangers, knock-out pots, and water seals,~~ installed to prevent or minimize the combustion of ~~vent gas~~ Vent Gas in a ~~flare~~ Flare and includes, but is not limited to, compressors, pumps, heat exchangers, knock-out pots, and water seals.

~~(7)~~(10) FLARE MINIMIZATION PLAN is a ~~document~~ compliance plan prepared by a Facility and approved by the Executive Officer that is intended to meet the requirements of ~~subdivision (e)~~ subdivision (f) or (g).

(11) FLARE MONITORING AND RECORDING PLAN (FMRP) is a compliance plan prepared by a Facility and approved by the Executive Officer that is intended to meet the requirements in paragraph (i)(1).

~~(8)~~(12) FLARE MONITORING SYSTEM is the ~~monitoring and recording~~ equipment used ~~for the determination of~~ to monitor and record the ~~flare~~ Flare operating parameters, including higher heating value, total sulfur concentration, combustion efficiency, standard volumetric flow rate, and/or on/off flow indication.

(13) FLARE TIP VELOCITY is the velocity of ~~flare~~ a Flare gas~~es~~ stream exiting a ~~flare~~ Flare tip averaged over 15 minute time periods, starting at 12 midnight to 12:15 am, ~~12:15 am to 12:30 am, and so on,~~ and concluding at 11:45 pm to midnight, and calculated as the volumetric flow of Vent Gas divided by the cross sectional area of the ~~flare~~ Flare tip, as specified in Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR Part 63 Subpart CC, section 670, paragraph (d)).

~~(9)~~(14) HYDROGEN PRODUCTION CAPACITY is the maximum rated capacity of the Hydrogen Production Plant to produce hydrogen in million standard cubic feet (MMSCF) of hydrogen per year calculated based on the maximum daily rated capacity, pursuant to Attachment C: Processing Capacity of Refineries and Production Capacity of Hydrogen Production Plants (Attachment C).

~~(10)~~(15) HYDROGEN PRODUCTION PLANT is a Unit within a Refinery, or a separate ~~facility~~ Facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes, using refinery fuel gas, process gas, or ~~natural gas~~ Natural Gas, and which primarily supplies hydrogen for ~~petroleum refinery~~ Refinery operations.

~~(11)~~(16) NATURAL GAS is a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

~~(12) NOTICE OF SULFUR DIOXIDE EXCEEDANCE is a notice issued by the Executive Officer to the owner or operator when the petroleum refinery has exceeded a performance target of this rule.~~

(17) OXIDES OF NITROGEN (NOx) EMISSIONS is the sum of nitric oxide and nitrogen dioxide emitted, calculated, and expressed as nitrogen dioxide.

(18) PERFORMANCE TARGET is an annual threshold on the amount of sulfur dioxide emissions or NOx Emissions calculated over one calendar year that can be emitted from a Facility before certain actions are triggered pursuant to paragraph (f)(4).

~~(13) PETROLEUM REFINERY is a facility that processes petroleum, as defined in the North American Industry Classification System (NAICS) as Industry No. 324110, Petroleum Refineries. For the purpose of this rule, all portions of the petroleum refining operation, including those at non-contiguous locations operating flares, shall be considered as one petroleum refinery.~~

~~(14)~~(19) PILOT is an auxiliary burner used to ignite the ~~vent gas~~ Vent Gas routed to a ~~flare~~ Flare.

~~(15)~~(20) PLANNED FLARE EVENT is any flaring of Vent Gas as a result ~~from process unit(s) or equipment~~ of a scheduled ~~startup~~ Startup, ~~shutdown~~ Shutdown, ~~turnaround~~ Turnaround, ~~maintenance, clean-up~~ LPG tank cleaning, ~~and~~ or non-emergency flaring of any process unit or equipment. ~~Flaring from the startup of a process unit or equipment that is more than 36 hours after the end of an unplanned flare event of that same process unit shall be considered a Planned Flare Event.~~

(21) PROCESSING CAPACITY is the amount of crude oil and/or alternative feedstocks, which includes organic material that is not derived from crude oil product, coal, Natural Gas, or any other fossil-fuel based organic material, that a Facility can process annually, pursuant to Attachment C.

~~(16)~~(22) PURGE GAS is a continuous gas stream introduced into a ~~flare~~ Flare header, ~~flare~~ Flare stack, and/or ~~flare~~ Flare tip for the purpose of maintaining a positive flow that prevents the formation of an explosive mixture due to ambient air ingress.

~~(17)~~(23) REPRESENTATIVE SAMPLE is a sample of ~~vent gas~~ Vent Gas collected from the location as approved in the Flare Monitoring and Recording Plan and analyzed utilizing test methods specified in ~~subdivision (j)~~ subdivision (k).

(24) REFINE is to convert crude oil or Alternative Feedstock to produce more usable products such as gasoline, diesel fuel, aviation fuel, lubricating oils, asphalt or petrochemical feedstocks, or any other similar product.

(25) REFINERY is a Facility that is permitted to Refine crude oil, as defined in the Standard Industrial Classification Manual as Industry No. 2911 and/or a facility that is permitted to Refine Alternative Feedstocks. All portions of the refining operation, including those at non-contiguous locations operating Flares, shall be considered as one Refinery.

(26) RELATIVE CAUSE is the identified category for the cause of any Flare Event where more than 5,000 cubic feet of Vent Gas is combusted at the flare, including Emergency, Shutdown, Startup, Turnaround, Essential Operational Need, or unknown if undeterminable.

~~(18)~~(27) SHUTDOWN is the procedure by which the operation of a process unit or piece of equipment is stopped due to the end of a production run, or for the purpose of performing maintenance, repair ~~and~~ or replacement of equipment. Stoppage caused by frequent breakdown due to poor maintenance or operator error shall not be deemed a ~~shutdown~~ Shutdown.

~~(19)~~(28) SMOKELESS CAPACITY is the maximum ~~vent gas~~ volumetric flow rate or mass flow rate of Vent Gas that a ~~flare~~ Flare is designed to operate without visible emissions.

~~(20)~~(29) SPECIFIC CAUSE ANALYSIS is a process used by a ~~facility~~ Facility ~~subject to this rule~~ to investigate the cause of a ~~flare event~~ Flare Event, identify corrective measures, and to prevent recurrence of a similar event.

~~(21)~~(30) STARTUP is the procedure by which a process unit or piece of equipment achieves normal operational status, as indicated by ~~such~~ parameters such as temperature, pressure, feed rate, and product quality.

~~(22)~~(31) SULFUR RECOVERY PLANT is Units within a Refinery, or a separate ~~facility~~ Facility that recovers elemental sulfur or sulfur compounds from sour gases and/or sour water generated by ~~petroleum refineries~~ Refineries.

~~(23)~~(32) TURNAROUND is a planned activity involving ~~shutdown~~ Shutdown and ~~startup~~ Startup of one or ~~several~~ more process units for the purpose of performing periodic maintenance, repair ~~and~~or replacement of equipment, or installation of new equipment.

(33) UNPLANNED FLARE EVENT is any flaring of Vent Gas during operations such as an unplanned Shutdown and the subsequent Startup, breakdown, unforeseen maintenance, customer order kick back, or as a result of any situation beyond the operator's control including external power and/or external water curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters, acts of war or terrorism.

~~(24)~~(34) VENT GAS is any gas generated at a ~~facility~~ Facility ~~subject to this rule~~ that is routed to a ~~flare~~ Flare, excluding assisting air or steam, which ~~are~~ is injected into the ~~flare~~ Flare combustion zone or ~~flare~~ Flare stack via separate lines.

~~(25)~~(35) VOLATILE ORGANIC COMPOUNDS (VOC) is as defined in Rule 102 – Definition of Terms.

~~(26) WEB-BASED FLARE EVENT NOTIFICATION SYSTEM is a web page that allows facilities to notify the District about flaring events and to enter information such as the time that flaring begins and ends, vent gas flow rates, and emissions.~~

~~(c)~~(d) Requirements

(1) The owner or operator of a ~~petroleum refinery, sulfur recovery plant or hydrogen production plant~~ Facility ~~subject to this rule~~ shall:

~~(1)~~(A) Maintain a ~~pilot~~ Pilot flame present at all times a ~~flare~~ Flare is operational.;

~~(2)~~(B) Operate all ~~flares~~ Flares in a smokeless manner with no visible emissions except for periods not to exceed a total of five minutes during two consecutive hours, as determined by the test method in ~~paragraph (j)(2)~~ paragraph (k)(2).;

~~(3)~~(C) Except as specified in ~~(c)(10)~~ paragraph (d)(7), operate all ~~general service flares~~ General Service Flares at ~~petroleum refineries~~

Facilities such that the ~~flare tip velocity~~ Flare Tip Velocity is less than~~:~~

~~(A)~~ 60 feet per second, or the lesser of 400 feet per second and $V_{Max}$, where:

$$\mathrm{Log}_{10}(\mathrm{V}_{\mathrm{Max}}) = \frac{\text{Net Heating Value}_{\text{Vent Gas}} + 1{,}212}{850}$$

and the Net Heating Value$_{\text{Vent Gas}}$ in ~~British Thermal Units~~ Btu per standard cubic foot is determined and calculated as specified in ~~pursuant to monitoring required in subdivision (g)~~ paragraph (j)(5);~~.~~

~~(4)~~(D) ~~Effective January 30, 2019,~~ Operate ~~general service flares~~ General Service Flares ~~at petroleum refineries shall~~ in a manner to maintain the net heating value of the ~~flare~~ Flare combustion zone gas ($NHV_{cz}$) at or above 270 ~~British Thermal Units~~ Btu per standard cubic feet, averaged over a 15-minute period. The owner or operator shall calculate $NHV_{cz}$ as specified in ~~Title 40 of the Code of Federal Regulations~~ 40 CFR Part 63 Subpart CC, section 670~~—National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.~~;

(E) Operate all Flares in such a manner that minimizes all flaring;

(F) Route no Vent Gas to the Flare except during Emergencies, Shutdowns, Startups, Turnarounds, or Essential Operational Needs; and

(G) Prevent Vent Gas with a hydrogen sulfide concentration in excess of 160 parts per million by volume (ppmv), averaged over three hours, from being routed to the Flare except during Emergencies, Shutdowns, or Startups.

(2) The owner or operator of a Facility shall deem the start of a Flare Event as when the Vent Gas flow velocity exceeds 0.10 feet per second and deem the end of the Flare Event as when the Vent Gas flow velocity drops below 0.12 feet per second, or when the owner or operator can demonstrate that no more Vent Gas was combusted based upon the monitoring records of the Flare water seal level and/or other parameters as defined by the Executive Officer in an approved FMRP pursuant to subdivision (i).

(3) The owner or operator of a new Facility, or an existing non-operating Facility, that commences or resumes operations, other than from standard Turnarounds or process unit Shutdown shall:

(A) No later than 180 days prior to the initial commencement or resumption of operations, submit a new or revised FMRP pursuant to paragraph (i)(1) to the Executive Officer for approval~~.~~; and

(B) No earlier than 14 days prior and no later than seven days prior to the date the owner or operator commences or resumes operations, provide the Executive Officer a written notice of the date of initial commencement or resumption of operations.~~; and~~

~~(5)~~(4) The owner or operator of a Facility shall ~~C~~conduct an annual acoustical or temperature leak survey of all pressure relief devices connected directly to a ~~flare~~ Flare and shall repair leaking pressure relief devices no later than the next ~~turnaround~~ Turnaround. The survey shall be conducted no earlier than 90 days prior to the scheduled process unit ~~turnaround~~ Turnaround.

~~(6)~~(5) The owner or operator of a Facility shall ~~C~~conduct a Specific Cause Analysis for any ~~flare event~~ Flare Event, excluding planned ~~shutdown~~Shutdown, planned ~~startup~~ Startup, and ~~turnarounds~~Turnarounds, ~~when any of the thresholds in (c)(6)(A) through (C) is exceeded.~~ unless the Flare ~~events~~ Event ~~resulting~~ resulted from a non-standard operating procedure that occurred during a planned ~~shutdown~~Shutdown, planned ~~startup~~ Startup, or ~~turnaround~~ Turnaround, ~~must also conduct a Specific Cause Analysis~~ when any of the following thresholds ~~in (c)(6)(A) through (C)~~ is exceeded~~.~~:

(A) ~~Emissions exceed~~ 100 pounds of VOC emissions; ~~or~~

(B) ~~Emissions exceed~~ 500 pounds of sulfur dioxide emissions; or

(C) ~~More than~~ 500,000 standard cubic feet of ~~vent gas~~ Vent Gas ~~are~~ is combusted.

~~(7)~~(6) ~~Effective January 30, 2019,~~ The owner or operator of a Facility shall conduct a Specific Cause Analysis for any ~~flare event~~ Flare Event at a ~~petroleum refinery~~ Facility when the ~~smokeless capacity~~ Smokeless Capacity of the ~~flare~~ Flare is exceeded and ~~either~~:

(A) The visible emission limit~~s~~ in ~~paragraph (c)(2)~~ subparagraph (d)(1)(B) or Rule 401 – Visible Emissions ~~are~~ is exceeded; or

(B) The ~~flare tip velocity~~ Flare Tip Velocity limit~~s~~ in ~~subparagraph (c)(3)(A)~~ subparagraph (d)(1)(C) is exceeded.

~~(8) Submit all Specific Cause Analyses as required by paragraphs (c)(6) or (c)(7) to the Executive Officer within 30 days of the start of the flare event, identifying the cause and duration of the flare event, and any mitigation and corrective actions taken or to be taken to prevent recurrence of a similar event. The owner or operator may request that the Executive Officer grant an extension of up to 15 days to submit the Specific Cause Analysis.~~

~~(9) All corrective actions identified in a Specific Cause Analysis required under paragraph (c)(6) or (c)(7) shall be implemented within 45 days of the flare event for which the Specific Cause Analysis was required. A corrective action identified in a Specific Cause Analysis may be implemented more than 45 days after the flare event if justified in a Specific Cause Analysis by showing the required elements in (c)(9)(A):~~

~~(A) An implementation schedule to complete the corrective action as soon as practicable,an explanation of the reason(s) why more than 45 days is needed to complete the corrective action, and a demonstration that the implementation schedule is the soonest practicable.~~

~~(B) After reviewing the Specific Cause Analysis, the Executive Officer may request additional information justifying why the implementation schedule beyond 45 days is the soonest practical.~~

~~(C) Within 30 days of receipt of all information necessary to evaluate the Specific Cause Analysis, the Executive Officer may require a modification to the corrective action or schedule, including increments of progress, and shall notify the operator in writing with an explanation describing why the corrective action is inadequate or the schedule can be shortened.~~

~~(10)~~(7) ~~Effective January 30, 2019, no flare event at a petroleum refinery shall occur~~ The owner or operator of a Facility shall not operate a Flare above ~~the~~ its ~~smokeless capacity~~ Smokeless Capacity ~~of the flare~~ during a Flare Event that exceeds the visible emission limit in subparagraph (d)(6)(A) or the Flare Tip Velocity limit in subparagraph (d)(6)(B), under the following conditions:

(A) ~~When the limits in clauses (c)(10)(D)(i) or (ii) are exceeded and~~ A single ~~the flare event~~ Flare Event that is due to operator error or poor maintenance;~~.~~

(B) Two ~~times~~ Flare Events at a ~~flare~~ Flare in any consecutive ~~three year~~ three-year period, ~~if the flare events exceed the limits in clauses (c)(10)(D)(i) or (ii)~~ and a Specific Cause Analysis pursuant to subdivision (e) shows the same cause for both ~~flare events~~ Flare Events from the same equipment~~.~~; or

(C) Three ~~times~~ Flare Events at a ~~flare~~ Flare in any consecutive ~~three year~~ three-year period, ~~if the flare events exceed the limits in clauses (c)(10)(D)(i) or (ii),~~ and the ~~flare events~~ Flare Events are due to any cause.

~~(D) Pursuant to subparagraphs (c)(10)(A) through (C), flare events shall not exceed:~~

~~(i) The visibility limits in paragraph (c)(2) or Rule 401; or~~

~~(ii) The velocity limits in subparagraph (c)(3)(A).~~

~~(E)~~(8) If more than one ~~flare~~ Flare is operated above the Smokeless Capacity and exceeds ~~the limits pursuant to in (c)(10)(D)(i) or (ii)~~ the visible emission limit in subparagraph (d)(6)(A) or the Flare Tip Velocity limit in subparagraph (d)(6)(B) during a single ~~event~~ Flare Event, and a Specific Cause Analysis prepared pursuant to subdivision (e) demonstrates that the ~~flaring events~~ Flare Events at these ~~flares~~ Flares have the same root cause, then one ~~flaring event~~ Flare Event at each ~~flare~~ Flare shall be considered to have exceeded ~~these limits~~ the visible emission limit in subparagraph (d)(6)(A) or the Flare Tip Velocity limit in subparagraph (d)(6)(B).

~~(F)~~(9) Notwithstanding the provisions in Rule 430 – Breakdown Provisions (Rule 430) and Rule 2004 – Requirements (Rule 2004), the prohibitions listed in ~~paragraph (c)(10)~~ paragraph (d)(7) ~~of this rule~~ shall be applicable during all periods including breakdowns, ~~with the exception of~~ except for exemptions listed in ~~subdivision (k)~~ subdivision (m).

~~(11)~~(10) The owner or operator of a Facility shall ~~C~~conduct an analysis and determine the ~~relative cause~~ Relative Cause of any ~~other flare events~~ Flare Event where more than 5,000 standard cubic feet of ~~vent gas~~ Vent Gas ~~are~~ is combusted at the Flare and report the Relative Cause in the quarterly reports pursuant to subparagraph (j)(15)(D), and ~~. W~~when it is not feasible to determine the ~~relative cause~~ Relative Cause, state the reason why it was not feasible to make the determination and retain the records of the Relative Cause analysis pursuant to paragraph (j)(12).

~~(12) Maintain the following information and submit to the Executive Officer upon request:~~

~~(A) Detailed process flow diagrams of all upstream equipment and process units venting to each flare and a complete description and technical specifications for each flare system components such as flares, associated knock-out pots, surge drums, water seals and flare gas recovery systems, and an audit of the vent gas recovery capacity of each flare system, the available storage for excess vent gases and the scrubbing capacity available for vent gases, including any limitations associated with scrubbing vent gases for use as a fuel; and~~

~~(B) A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring; and~~

~~(C) A descriptions of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring. The description shall specify the scheduled year of installation or implementation.~~

~~(13) Submit to the Executive Officer 12 months after July 7, 2017 a Scoping Document that evaluates the feasibility of minimizing flaring emissions that includes the following components:~~

~~(A) The Scoping Document shall describe how a facility operator or owner can reduce emissions from all planned flare events and essential operational needs flare events, to emission limits specified in subparagraph (c)(13)(B). The Scoping Document shall describe two potential alternatives for each applicable level in (c)(13)(B)(i) through (iv), and shall include an analysis of the following:~~

~~(i) proposed physical controls and/or operating practices,~~

~~(ii) technical feasibility constraints,~~

~~(iii) approximate cost (initial capital and ongoing),~~

~~(iv) timing constraints.~~

~~(B) The Scoping Document shall analyze the feasibility of achieving each of the following annual emission levels for planned flare events and essential operational needs as soon as feasible:~~

~~(i) 0.10 tons of sulfur oxides per million barrels of a petroleum refinery's 2004 calendar year crude processing capacity,~~

~~(ii) 0.05 tons of sulfur oxides per million barrels of a petroleum refinery's 2004 calendar year crude processing capacity, and~~

~~(iii) 0.01 tons or lower of sulfur oxides per million barrels of a petroleum refinery's 2004 calendar year crude processing capacity, and~~

~~(iv) 0.1 tons per year of volatile organic compounds from flares that only vent clean service streams.~~

~~(C) Using the criteria described in clauses (c)(13)(A)(i) through (iv), the Scoping Document shall analyze the feasibility of installing and maintaining at least three physical or automated process controls as soon as feasible that can be used together or separately to avoid or minimize emergency flare events described in (c)(13)(C)(i) through (iv).~~

~~(i) A sudden influx of vent gas into a flare gas header. The amount of vent gas is equivalent to the highest vent gas flow rate, averaged over a 15-minute period, vented to the flare gas header from all emergency flare events at that flare since January 1, 2012.~~

~~(ii) A sudden loss of the process unit with the highest fuel gas consumption rate of recovered flare gas at that facility, averaged over a 15-minute period, since January 1, 2012.~~

~~(iii) A sudden loss of all external electrical power to the facility.~~

~~(iv) A sudden loss of all electrical power from any non-backup electrical generation unit that is currently operating at a facility.~~

~~(D) For each flare operated at the facility, the Scoping Document shall contain a description of:~~

~~(i) The smokeless capacity, and documentation for how the smokeless capacity was determined;~~

~~(ii) The maximum vent gas flow rate;~~

~~(iii) The maximum supplemental gas flow rate;~~

~~(iv) Process flow diagram which shows all gas lines that are associated with the flare (e.g., waste, purge, supplemental gases, assist steam);~~

~~(v) Detailed process flow diagrams of all associated upstream equipment and process units venting to each flare, with a~~

~~general description of components, identifying the type and location of each flare and all associated control equipment including but not limited to knockout drums, flare headers, assist, and ignition systems.~~

~~(14) Operate all flares in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds or essential operational needs.~~

~~(15) Prevent the combustion in any flare of vent gas with a hydrogen sulfide concentration in excess of 160 ppm, averaged over three hours, excluding any vent gas resulting from an emergency, shutdown, startup, or process upset.~~

(e) Specific Cause Analysis Requirements

(1) The owner or operator of a Facility that is required to conduct multiple Specific Cause Analyses pursuant to paragraph (d)(6) satisfies the applicable requirements with a single Specific Cause Analysis for any single continuous Flare Event under the following scenarios:

(A) The Flare Event exceeds the Smokeless Capacity of the Flare, the visible emission limit in subparagraph (d)(6)(A), and the Flare Tip Velocity limit in subparagraph (d)(6)(B);

(B) Regardless of the count of 15-minute block periods in which the Flare Tip Velocity was exceeded or the count of 2-hour block periods that contains more than five minutes of visible emissions;

(C) The Flare Event causes two or more Flares that are operated in series (i.e., cascaded Flare systems) to have a Flare Event that exceeds the Smokeless Capacity of the Flare and exceeds either the visible emission limit in subparagraph (d)(6)(A) or the Flare Tip Velocity limit in subparagraph (d)(6)(B); or

(D) The Flare Event causes two or more Flares to have a Flare Event that exceeds the Smokeless Capacity of the Flare and exceeds either the visible emission limit in subparagraph (d)(6)(A) or the Flare Tip Velocity limit in subparagraph (d)(6)(B), regardless of the configuration of the Flares, if the cause is reasonably expected to be an external power curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters or acts of war or terrorism.

(2) Except as provided in subparagraphs (e)(1)(C) and (e)(1)(D), if more than one Flare has a Flare Event that exceeds the Smokeless Capacity of the Flare and exceeds either the visible emission limit in subparagraph (d)(6)(A) or the Flare Tip Velocity limit in subparagraph (d)(6)(B) during the same time period, an initial Specific Cause Analysis shall be conducted separately for each Flare. If the initial Specific Cause Analysis indicates that the Flare Events have the same root cause(s), the initially separate Specific Cause Analyses may be recorded as a single Specific Cause Analysis and a single corrective action analysis may be conducted.

(3) The owner or operator of a Facility shall submit the Specific Cause Analysis report for any Flare Event as required by paragraph (d)(5) or (d)(6) to the Executive Officer within 30 days of the start of the Flare Event pursuant to paragraph (j)(17) or (j)(18) and include all the following:

(A) The cause and duration of the Flare Event; and

(B) Any mitigation and corrective actions taken or to be taken to prevent recurrence of a similar event.

(4) Within 14 days of the Flare Event, the owner or operator may submit a written request to be granted an extension of up to 15 days to submit the Specific Cause Analysis report required pursuant to paragraphs (d)(5) and (d)(6), which may be approved by the Executive Officer if the request is submitted within the 14-day deadline.

(5) Except as provided for in paragraph (e)(6), within 45 days of the Flare Event for which the Specific Cause Analysis was required, the owner or operator of a Facility shall implement all corrective actions identified in a Specific Cause Analysis report pursuant to paragraph (e)(3).

(6) Within 14 days of the Flare Event, the owner or operator of a Facility may submit a written request to be granted additional time beyond the 45 days required in subparagraph (e)(5) to implement corrective action(s). The owner or operator of a Facility must submit the following additional information in the Specific Cause Analysis report submitted pursuant to paragraph (e)(3):

(A) An implementation schedule to complete the corrective action(s) as soon as practicable;

(B) An explanation of the reason(s) why more than 45 days is needed to complete the corrective action(s); and

(C) A demonstration that the implementation schedule is the soonest practicable.

(7) After reviewing the corrective action(s) time extension request submitted pursuant to subparagraph (e)(6), the Executive Officer may request additional information justifying the implementation schedule beyond 45 days. Failure to provide the requested information may result in the denial of an extension beyond 45 days and corrective action(s) must be implemented as soon as practicable, but no later than 45 days from the Flare Event.

(8) After reviewing the Specific Cause Analysis report, the Executive Officer may require the owner or operator to modify the corrective action(s) or schedule and submit increments of progress. The Executive Officer shall notify the owner or operator in writing if the corrective action(s) is inadequate, or the implementation schedule must be shortened.

(9) Within 45 days of the Flare Event or no later than the extended schedule pursuant to paragraph (e)(6), the owner or operator of a Facility shall report the record of corrective action(s) completed to date pursuant to paragraph (j)(17) or (j)(18).

~~(d)~~(f) Performance Targets Requirements

(1) The owner or operator of a ~~petroleum refinery~~ Refinery or Sulfur Recovery Plant ~~subject to this rule~~ shall:

(A) ~~m~~Minimize ~~flare~~ Flare emissions and meet ~~a~~ the applicable ~~performance target~~ Performance Target for sulfur dioxide emissions from flares ~~of less than 0.5 tons per million barrels of crude processing capacity, calculated as an average over one calendar year~~, pursuant to the schedule in Table 1;~~.~~ and

**TABLE 1 – Performance Target Schedule for Sulfur Dioxide**

| **$SO_2$ Performance Target (Ton per Million Barrels)** | **Effective Date** |
|---|---|
| 0.5 | Calendar Years 2024 to 2025 |
| 0.35 | Calendar Years 2026 to 2028 |
| 0.25 | Calendar Year 2029 and thereafter |

~~(1)~~(B) Demonstrate ~~C~~compliance with ~~this~~ the ~~performance target~~ Performance Target in subparagraph (f)(1)(A) ~~shall be determined~~ at the end of each calendar year based on the ~~facility's~~ Facility's annual ~~flare~~ Flare sulfur dioxide emissions normalized over the Facility's ~~crude oil processing capacity~~ Processing Capacity ~~in calendar year 2004~~ as listed in Attachment C Table C1.

(2) For calendar year 2025 and after, the owner or operator of a Hydrogen Clean Service Flare shall:

(A) Minimize Flare emissions and meet an annual Performance Target of 0.3 pound of NOx Emissions per Hydrogen Production Capacity of the Hydrogen Production Plant; and

(B) Demonstrate compliance with the Performance Target in subparagraph (f)(2)(A) at the end of each calendar year based on the Hydrogen Production Plant's annual Flare NOx Emissions normalized over the Hydrogen Production Capacity of the Hydrogen Production Plant as listed in Attachment C Table C2.

~~(2)~~(3) In the event the ~~petroleum refinery~~ Facility exceeds ~~specific~~ the applicable ~~performance target~~ Performance Target ~~of subdivision (d)~~ in subparagraph (f)(1)(A) or (f)(2)(A) ~~is exceeded~~ for any calendar year, the Executive Officer may issue a written ~~Notice of Sulfur Dioxide Exceedance~~ notice of emissions exceedance to the Facility ~~that shall become a part of the refinery compliance record~~.

~~(3)~~(4) In the event the ~~petroleum refinery~~ Facility exceeds ~~specific~~ the applicable ~~performance target~~ Performance Target ~~of subdivision (d)~~ in subparagraph (f)(1)(A) or (f)(2)(A) ~~is exceeded~~ for any calendar year, the owner or operator of the ~~petroleum refinery~~ Facility shall:

(A) Within 90 days following the end of a calendar year:

(i) Submit a Flare Minimization Plan pursuant to ~~subdivision (e)~~ paragraph (h)(1);~~,~~ and

~~(B)~~(ii) Pay the ~~District~~ South Coast AQMD mitigation fees~~, within 90 days following the end of a calendar year~~ for the calendar year for which the ~~performance target~~ Performance Target was exceeded, ~~according to the following schedule~~ consistent with Attachment D: Guidelines for Calculating Mitigation Fees for Performance Targets Exceedance (Attachment D);~~:~~ or

(B) If the owner or operator of a Facility elects to submit alternative data substitution for any periods of invalid or missing monitoring data within the calendar year, the owner or operator of the Facility shall:

(i) Within 60 days following the end of the calendar year for which the Performance Target was exceeded, submit supporting data for alternative data substitution pursuant to Attachment B: Guidelines for Emissions Calculations (Attachment B), for approval by the Executive Officer;

(ii) If the Executive Officer provides written notification that the alternative data substitution submitted pursuant to clause (f)(4)(B)(i) is insufficient, the owner or operator of the Facility may submit additional supporting data within 30 days of receiving written notification;

(iii) If the Executive Officer provides a written notification that the alternative data substitution re-submitted pursuant to clause (f)(4)(B)(ii) is insufficient, the alternative data substitution will be deemed disapproved, and the owner or operator of the Facility shall apply the standard data substitution procedures in Attachment B;

(iv) No later than 90 days from issuance of the final written notification from the Executive Officer regarding approval or disapproval of the alternative data substitution, if the applicable data confirms the Facility's exceedance from the applicable Performance Target, the owner or operator of a Facility shall:

(A) Submit a Flare Minimization Plan pursuant to paragraph (h)(1); and

(B) Pay the South Coast AQMD mitigation fees, for the calendar year for which the Performance Target was exceeded, pursuant to Attachment D.

~~(i) If excess emissions are no more than ten percent of the petroleum refinery specific performance target, $25,000 per ton for all sulfur dioxide emission(s) in excess of the applicable performance target, or~~

~~(ii) If excess emissions are greater than ten percent but no more than twenty percent of the petroleum refinery specific~~

~~performance target, $50,000 per ton of all sulfur dioxide emission(s) in excess of the applicable performance target, or~~

~~(iii) If excess emissions are greater than twenty percent of the petroleum refinery specific performance target, $100,000 per ton of all sulfur dioxide emission(s) in excess of the applicable performance target.~~

(g) Non-Hydrogen Clean Service Flares Requirements

(1) An owner or operator of a Refinery with a Non-Hydrogen Clean Service Flare that exceeded a throughput level with total heat content of 15,000 MMBtu per year (based on higher heating value of total Vent Gas and Purge Gas) for any two consecutive years prior to [*Date of Rule Adoption*] since 2017 shall:

(A) Within 18 months from [*Date of Rule Adoption*] submit to the Executive Officer a complete permit application to install equipment or implement changes to reduce the throughput to a level with total heat content not to exceed 15,000 MMBtu per year (based on higher heating value of total Vent Gas and Purge Gas); and

(B) No later than 12 months from the date that the permit is issued, or the date included in the permit extension if a request for a permit extension pursuant to Rule 205 – Expiration of Permits to Construct (Rule 205) is approved in writing, install equipment or implement changes to reduce the throughput to a level with total heat content (based on higher heating value of total Vent Gas and Purge Gas) not to exceed 15,000 MMBtu per year.

(2) Effective January 1, 2026 or 24 months after permit is issued pursuant to subparagraph (g)(1)(A), whichever occurs later, the owner or operator of a Refinery that exceeds a throughput level with total heat content of 15,000 MMBtu per year (based on higher heating value of total Vent Gas and Purge Gas) at each Non-Hydrogen Clean Service Flare for two consecutive calendar years shall submit a Flare Minimization Plan pursuant to paragraph (h)(2).

~~(e)~~(h) Flare Minimization Plan Requirements and Schedule

(1) The owner or operator of a ~~petroleum refinery~~ Facility exceeding the ~~performance target~~ Performance Target in ~~subdivision (d)~~ subparagraph (f)(1)(A) or (f)(2)(A) shall submit~~, no later than 90 days after the end of a calendar year with emissions exceeding the annual performance target,~~ a complete Flare Minimization Plan, or may elect to submit a complete revised Flare Minimization Plan for the owner or operator of a Facility with an existing approved Flare Minimization Plan, for ~~approval~~ review by the Executive Officer, pursuant to the schedule in paragraph (f)(4). ~~This plan shall constitute a plan pursuant to Rule 221 and fees shall be assessed pursuant to Rule 306.~~ The ~~plan application~~ Flare Minimization Plan ~~shall list all actions to be taken by the petroleum refinery to meet the performance target in subdivision (d), and~~ shall include the following information:

~~(A) A complete description and technical specifications for each flare and associated knock-out pots, surge drums, water seals and flare gas recovery systems;~~

~~(B)~~(A) Any specific change to ~~Refinery~~ Facility policies and procedures to be implemented and any equipment improvements to minimize flaring and ~~flare~~ Flare emissions ~~and~~ to comply with the ~~performance target~~ Performance Target of ~~subdivision (d)~~ subparagraph (f)(1)(A) or (f)(2)(A) for:

(i) ~~Planned turnarounds~~ Turnarounds and other scheduled maintenance, based on an evaluation of these activities during the previous five years;

(ii) Essential Operational Needs ~~operational needs~~ and the technical reason for which the ~~vent gas~~ Vent Gas cannot be prevented from being flared during each specific situation, based on supporting documentation on ~~flare gas recovery systems~~ Flare Gas Recovery Systems, excess gas storage and gas treating capacity available for each ~~flare~~ Flare; and

(iii) Emergencies, including procedures that will be used to prevent recurring equipment breakdowns and process upsets, based on an evaluation of the adequacy of maintenance schedules for equipment, process and control instrumentation~~.~~;

~~(C)~~(B) Any ~~flare gas recovery equipment and treatment system(s)~~ Flare Gas Recovery System to be installed to comply with the ~~performance targets~~ Performance Target ~~of subdivision (d)~~ in subparagraph (f)(1)(A) or (f)(2)(A).

(2) The owner or operator of a Refinery that exceeds the annual throughput threshold pursuant to paragraph (g)(2) shall:

(A) No later than 90 days from the end of the second consecutive calendar year, submit a Flare Minimization Plan, or a complete revised Flare Minimization Plan for the owner or operator of a Facility with an existing approved Flare Minimization Plan, for review by the Executive Officer. The Flare Minimization Plan shall list all specific procedure changes to be implemented by the Facility to meet the annual throughput threshold in paragraph (g)(2), and shall include the following information:

(i) List of corrective action(s), including but not limited to applicable technology(s) or technique(s), that will be used to reduce the amount of combusted Vent Gas in the Non-Hydrogen Clean Service Flare to below the threshold; and

(ii) Schedule to implement the action(s);

(B) Implement the corrective action(s) in compliance with the schedule provided pursuant to subparagraph (h)(2)(A).

(3) The owner or operator of a Facility required to submit a Flare Minimization Plan or a revised Flare Minimization Plan pursuant to this subdivision shall include a complete application pursuant to Rule 221 – Plans (Rule 221) and appropriate fees pursuant to Rule 306 – Plan Fees (Rule 306).

~~(2)~~(4) The Executive Officer will make the Flare Minimization Plans available for public review for a period of 60 days and respond to any received comments ~~received~~ prior to plan approval.

(5) Flare Minimization Plan Review

The Executive Officer will ~~approve~~ review ~~a plan~~ the Flare Minimization Plan ~~upon~~ to determin~~e~~ing ~~that~~ if it meets the requirements of ~~subdivision (e)~~ paragraph (h)(1) or (h)(2), ~~or~~ and notify the owner or operator of the Facility in writing ~~that~~ if the plan is deficient and specify the required corrective action(s). If the owner or operator fails to submit an amendment to correct the deficiency within 45 days ~~to correct the deficiency~~ of receiving the written notification from Executive Officer:~~,~~

(A) ~~the~~The Executive Officer will deny the Flare Minimization Plan~~.~~; and

(B) The ~~facility~~ Facility shall be deemed in violation of this rule ~~upon the Executive Officer's denial of the Flare Minimization Plan~~.

~~(3) The owner or operator of a petroleum refinery having an existing approved Flare Minimization Plan shall, no later than 90 days after the end of a calendar year, submit for the approval of the Executive Officer a revised Flare Minimization Plan, subject to the provisions of paragraphs (e)(1) and (e)(2), in the event the annual performance target for that calendar year is exceeded.~~

~~(4)~~(6) The owner and operator of a ~~petroleum refinery~~ Facility shall comply with all provisions of an approved Flare Minimization Plan.

(7) Violation of any of the terms of the Flare Minimization Plan ~~plan is~~ shall constitute a violation of this rule.

~~(f)~~(i) Flare Monitoring and Recording Plan Requirements

(1) The owner or operator of an existing ~~petroleum refinery, sulfur recovery plant or hydrogen production plant~~ Facility, upon modification or replacement of any monitoring equipment included in an approved ~~Flare Monitoring and Recording Plan~~ FMRP, shall submit a revised ~~Flare Monitoring and Recording Plan~~ FMRP~~, complete with an application and appropriate fees, for each facility~~ to the Executive Officer for approval~~. This plan shall constitute a plan pursuant to Rule 221 and fees shall be assessed pursuant to Rule 306. Each Flare Monitoring and Recording Plan shall contain the information described in paragraph (f)(4) of this rule.~~ that includes, at a minimum, the following:

(A) A Facility plot plan showing the location of each Flare in relation to the general plant layout;

(B) Type of Flare service, as defined in paragraph (c)(6), and information regarding design capacity, operation and maintenance for each Flare;

(C) The following information regarding Pilot and Purge Gas for each Flare:

(i) Type(s) of gas used;

(ii) Actual set operating flow rate in standard cubic feet per minute;

(iii) Maximum total sulfur concentration expected for each type of gas used; and

(iv) Average higher (gross) heating value expected for each type of gas used;

(D) Drawing(s), preferably to scale with dimensions, and an as-built process flow diagram of the Flare(s) identifying major components, such as Flare header, Flare stack, Flare tip(s), or burner(s), any bypass line, Purge Gas system, Pilot gas system, ignition system, assist system, water seal, knockout drum and molecular seal;

(E) Detailed process flow diagrams identifying the type and location of each Flare and all associated control equipment including, but not limited to, knockout drums, Flare headers, assist systems, and ignition systems, and a representative flow diagram showing the interconnections of the Flare system(s) with vapor recovery system(s), process units and other equipment as applicable;

(F) A complete description of the assist system process control, flame detection system, and Pilot ignition system;

(G) A complete description of Vent Gas flaring process for an integrated gas flaring system which describes the method of operation of the Flares (e.g. sequential, etc.);

(H) A complete description of the Flare Gas Recovery System and vapor recovery system(s) which have interconnection to a Flare, such as compressor description(s), design capacities of each compressor and the vapor recovery system, and the method currently used to determine and record the amount of vapors recovered;

(I) Drawing(s) with dimensions, preferably to scale, showing the following information for Vent Gas:

(i) Sampling locations; and

(ii) Flow meter device(s), on/off flow indicators, higher heating value analyzer, and total sulfur analyzer locations and the method used to determine the location;

(J) A detailed description of manufacturer's specifications, including but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance, a quality assurance procedure and any other specifications and information referenced in Attachment A: Flare Monitoring System Requirements (Attachment A) for all existing and proposed flow metering devices, on/off flow indicating devices, higher heating value and total sulfur analyzers for Vent Gas;

(K) A complete description and the data used to determine and to set the actuating and de-actuating and the method to be used for verification of each setting for each on/off flow indicator;

(L) A complete description of proposed analytical and sampling methods or estimation methods, if applicable, for determining higher (gross) heating value and total sulfur concentration of the Flare Vent Gas;

(M) A complete description of the proposed data recording, collection, management, and any other specifications and information referenced in Attachment A for each Flare Monitoring System;

(N) A complete description of proposed method to determine, monitor and record total volume, higher heating value, and total sulfur concentration of Vent Gas to a Flare for each Flare Event pursuant to the requirements of this rule;

(O) For a new or an existing non-operating Facility starting or restarting operations, other than from standard Turnarounds or process unit Shutdowns, a schedule for the installation and operation of each Flare Monitoring System; and

(P) A complete description of any proposed alternative criteria to determine a sampling Flare Event for each specific Flare, if any, and detailed information used for the basis of establishing such criteria.

(2) The owner or operator of an existing ~~petroleum refinery, sulfur recovery plant or hydrogen production plant~~ Facility shall~~:~~

~~(A)~~ ~~C~~comply with all provisions of the most current ~~Flare Monitoring and Recording Plan~~ FMRP approved by the Executive Officer. The current plan shall remain in effect until ~~any~~ superseded by a revised ~~Flare Monitoring and Recording Plan~~ FMRP~~,~~ submitted pursuant to ~~paragraph (f)(1)~~ paragraph (i)(1) and approved by the Executive Officer.

~~(B) The owner or operator of a petroleum refinery, sulfur plant or hydrogen plant shall comply with all provisions of an approved Flare Monitoring and Recording Plan.~~

(3) ~~V~~A violation of any ~~of the~~ terms~~-~~ or provision of the ~~plan~~ approved FMRP ~~is~~ shall constitute a violation of this rule.

(4) The owner or operator of a Facility required to submit a FMRP or a revised FMRP pursuant to this subdivision shall include a complete application pursuant to Rule 221 and appropriate fees pursuant to Rule 306.

~~(3) The owner or operator of a new or an existing non-operating petroleum refinery, sulfur recovery plant or hydrogen production plant starting or restarting operations that were not shut down from a turnaround or other shut-down as part of normal operations on or after July 7, 2017 shall:~~

~~(A) Provide the Executive Officer a written notice of the date of start-up no later than seven (7) days prior to starting or commencing operations.~~

~~(B) No later than 180 days prior to the initial startup or resumption of operations, submit a complete application and appropriate fees for a Flare Monitoring and Recording Plan to the Executive Officer for approval. This plan shall constitute a plan pursuant to Rule 221 and fees shall be assessed pursuant to Rule 306. Each Flare Monitoring and Recording Plan shall contain the information described in paragraph (f)(4) of this rule.~~

~~(4) Each Flare Monitoring and Recording Plan shall include, at a minimum, the following:~~

~~(A) A facility plot plan showing the location of each flare in relation to the general plant layout.~~

~~(B) Type of flare service, as defined in paragraph (b)(4), and information regarding design capacity, operation and maintenance for each flare.~~

~~(C) The following information regarding pilot and purge gas for each flare:~~

~~(i) Type(s) of gas used;~~

~~(ii) Actual set operating flow rate in standard cubic feet per minute;~~

~~(iii) Maximum total sulfur concentration expected for each type of gas used; and~~

~~(iv) Average higher (gross) heating value expected for each type of gas used.~~

~~(D) Drawing(s), preferably to scale with dimensions, and an as-built process flow diagram of the flare(s) identifying major components, such as flare header, flare stack, flare tip(s) or burner(s), any bypass line, purge gas system, pilot gas system, ignition system, assist system, water seal, knockout drum and molecular seal.~~

~~(E) Detailed process flow diagrams identifying the type and location of each flare and all associated control equipment including but not limited to knockout drums, flare headers, assist, and ignition systems, and a representative flow diagram showing the interconnections of the flare system(s) with vapor recovery system(s), process units and other equipment as applicable.~~

~~(F) A complete description of the assist system process control, flame detection system and pilot ignition system.~~

~~(G) A complete description of the gas flaring process for an integrated gas flaring system which describes the method of operation of the flares (e.g. sequential, etc.).~~

~~(H) A complete description of the flare gas recovery system and vapor recovery system(s) which have interconnection to a flare, such as compressor description(s), design capacities of each compressor and the vapor recovery system, and the method currently used to determine and record the amount of vapors recovered.~~

~~(I) Drawing(s) with dimensions, preferably to scale, showing the following information for proposed vent gas:~~

~~(i) Sampling locations; and~~

~~(ii) Flow meter device(s), on/off flow indicators, higher heating value analyzer, and total sulfur analyzer locations and the method used to determine the location.~~

~~(J) A detailed description of manufacturer's specifications, including but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance, a quality assurance procedure and any other specifications and information referenced in Attachment A for all existing and proposed flow metering devices, on/off flow indicating devices, higher heating value and total sulfur analyzers for vent gas.~~

(K) ~~A complete description and the data used to determine and to set the actuating and de-actuating and the method to be used for verification of each setting for each on/off flow indicator.~~

~~(L) A complete description of proposed analytical and sampling methods or estimation methods, if applicable, for determining higher (gross) heating value and total sulfur concentration of the flare vent gas.~~

~~(M) A complete description of the proposed data recording, collection, management, and any other specifications and information referenced in Attachment A for each flare monitoring system.~~

~~(N) A complete description of proposed method to determine, monitor and record total volume, higher heating value, and total sulfur concentration of gases vented to a flare for each flare event pursuant to the requirements of this rule.~~

~~(O) For new or existing non-operating petroleum refinery, sulfur recovery plant or hydrogen production plant starting or restarting operations, other than from standard turnarounds or process unit shut-downs, on or after July 7, 2017, a schedule for the installation and operation of each flare monitoring system.~~

~~(P) A complete description of any proposed alternative criteria to determine a sampling flare event for each specific flare, if any, and detailed information used for the basis of establishing such criteria.~~

~~(g)~~(j) ~~Operation,~~ Monitoring, ~~and Recording~~ Recordkeeping, and Reporting Requirements

~~The owner or operator of a flare subject to this rule shall comply with the following:~~

(1) The owner or operator of a Facility shall maintain the following information and submit to the Executive Officer upon request:

(A) Detailed process flow diagrams of all upstream equipment and process units venting to each Flare and a complete description and technical specifications for each Flare system components such as Flares, associated knock-out pots, surge drums, water seals, and Flare Gas Recovery Systems, and an audit of the Vent Gas recovery capacity of each Flare Gas Recovery System, the available storage for excess Vent Gas, and the scrubbing capacity available for Vent

Gas, including any limitations associated with scrubbing Vent Gas for use as a fuel;

(B) A description of the equipment, processes and procedures installed or implemented to reduce flaring within the last five years; and

(C) A description of any equipment, processes, or procedures the owner or operator plans to install or implement to eliminate or reduce flaring, specifying the scheduled year of installation or implementation.

~~(1)~~(2) On or before six ~~(6)~~ months after approval of a ~~the Flare Monitoring and Recording Plan~~ FMRP or ~~Revised~~ revised ~~Flare Monitoring and Recording Plan~~FMRP, the owner or operator of a Facility shall start monitoring and recording in accordance with ~~subdivision (g)~~ this subdivision and the provisions in the approved ~~Flare Monitoring and Recording Plan~~ FMRP or ~~Revised Flare Monitoring and Recording Plan~~ revised FMRP.

~~(2) Notwithstanding the provisions in Rule 430 - Breakdown Provisions and Rule 2004 - Requirements, the Operation Monitoring and Recording Requirements of this rule shall be applicable during all periods including breakdowns except as specified in paragraph (g)(5)(A).~~

(3) The owner or operator of a Facility shall ~~P~~perform monitoring and recording of the operating parameters, as applicable, according to the monitoring and recording requirements, and frequency ~~shown~~ listed in ~~Table 1~~ Table 2 (including footnotes) ~~below~~, except as specified in ~~paragraph (g)(4) and (g)(5)~~ paragraph (j)(6).

**~~TABLE 1~~TABLE 2 – Operating Parameters Monitoring and Recording**

| TYPE OF FLARE | OPERATING PARAMETER | MONITORING AND RECORDING |
|---|---|---|
| Hydrogen Clean Service and Non-Hydrogen Clean Service | Gas Flow[1] | Measured and Recorded[2] Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)[3] |
| | Gas Higher Heating Value[~~3~~4] | Calculated or Continuously Measured and Recorded with a Higher Heating Value Analyzer |
| | Total Sulfur Concentration[~~4~~5] | Calculated or Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer |
| General Service | Gas Flow[1] | Measured and Recorded[2] Continuously with Flow Meter(s)[3] ~~with or without On/Off Flow Indicator(s)~~ |
| | Gas Higher Heating Value[~~3~~4] | Continuously Measured and Recorded with a Higher Heating Value Analyzer |
| | Total Sulfur Concentration[~~4~~5] | Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer |

1. Standard Cubic Feet per Minute~~.~~
2. All flow meters, flow indicators~~,~~ and recorders shall meet or exceed the minimum specifications in Attachment A~~.~~
3. On/Off flow indicators must be replaced with continuous flow meters pursuant to the compliance schedule in paragraph (j)(10) for Hydrogen Clean Service Flares

~~3.~~4. Higher (Gross) Heating Value in British Thermal Units per Standard Cubic ~~Foot~~Feet~~.~~

~~4.~~5. Total Sulfur as $SO_2$, ppmv~~.~~

(4) Alternative Flare Vent Gas Sampling

~~(A)~~

In cases where sampling of ~~vent gas~~ Vent Gas is exempted pursuant to ~~paragraph (k)(1)~~ paragraph (m)(1), the owner or operator of a ~~gas flare~~ Flare shall identify for each ~~flare event~~ Flare Event, the cause of event, the process system(s) involved, date and time event started~~, and~~ duration, and any other information related to the type of ~~vent gas~~ Vent Gas (e.g. total sulfur concentration) which is necessary to calculate ~~flare~~ Flare emissions using the guidelines in Appendix B for substituted data. The estimated emissions~~,~~ is subject to approval by the Executive Officer as representative of emissions from that ~~flare event~~ Flare Event~~,~~ and shall be reported and submitted with the quarterly report as specified in ~~paragraph (i)(4)~~ paragraph (j)(15).

(5) Flare Monitoring System Requirements

The owner or operator of a Facility shall determine the concentration of individual components in the Flare Vent Gas as specified in 40 CFR Part 63 Subpart CC, section 670, paragraph (j), if applicable.

~~(5)~~(6) Flare Monitoring System Downtime

~~(A)~~ The owner or operator of a Facility shall ~~M~~maintain and operate any ~~flare monitoring system~~ Flare Monitoring System~~,~~ used to ensure compliance with ~~paragraph (g)(3) of this rule,~~ paragraph (j)(3) in good operating condition at all times when the ~~flare~~ Flare that it serves is operational, except when out of service due to:

~~(i)~~(A) Breakdowns and unplanned system ~~maintenance~~ repair, which shall not exceed 96 hours, cumulatively, per quarter for each reporting period; or~~,~~

~~(ii)~~(B) Planned maintenance, which shall not exceed 14 days per an 18-month period commencing the start of ~~flare~~ Flare monitoring and recording, provided that a written notification detailing the reason for maintenance and methods that will be used during the maintenance period to determine emissions associated with flare events~~-~~is provided to the Executive Officer prior to, or within 24 hours of, removal of the monitoring system from service.

~~(B)~~(7) The owner or operator of a Facility may use ~~A~~a ~~flare monitoring system~~ Flare Monitoring System ~~may be used~~ to measure and record the operating parameters required in ~~paragraph (g)(3)~~ paragraph (j)(3) ~~of this rule~~ for more than one ~~flare~~ Flare, provided ~~that~~:

~~(i)~~(A) All the gases being measured and recorded are delivered to the ~~flare~~Flare(s) for combustion; and~~,~~

~~(ii)~~(B) ~~If the flare monitoring system is used to measure and record the operating parameters for general service flares, the flare monitoring system~~ Flare Monitoring System ~~shall~~ consists of a continuous ~~vent gas~~ Vent Gas flow meter, a continuous higher heating value analyzer, and a total sulfur analyzer and recorder that meet the requirements specified in Attachment A.

~~(6)~~(8) The owner or operator of a Facility shall ~~M~~monitor ~~the presence of a pilot~~ Pilot(s) ~~flame~~ using a thermocouple ~~or any other equivalent device approved by the Executive Officer~~ to detect the presence of a flame.

~~(7)~~(9) ~~Monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare and the flame of flares that are not enclosed, at a rate of no less than one frame per minute. Effective January 30, 2019,~~ The owner or operator of a Facility shall monitor all ~~flares~~ Flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the ~~flare~~ Flare, the flame of ~~flares~~ Flares that are not enclosed, and a sufficient area above the flame of all ~~flares~~ Flares that is suitable for visible emissions observations, at a ~~rate~~ frequency of no less than one frame every 15 seconds.

~~(8)~~(10) Effective on [*Date of Rule Adoption*] for General Service Flares, and effective on [*18 Months After Date of Rule Adoption*] for Hydrogen Clean Service Flares, the owner or operator of a Facility ~~All general service flares~~ shall:

(A) Have a continuous flow ~~meter~~ measuring device installed in a manner and at a location that ~~would~~ allows for accurate measurements of the total volume of ~~vent gas~~ Vent Gas to each ~~flare~~ Flare. If the flow meter cannot be placed in the location that ~~would~~ allows for accurate measurement due to physical constraints, the owner or operator shall retrofit or equip the existing flow meter(s) with totalizing capability to indicate the true net volume of gas flow to each ~~flare~~ Flare~~.~~; and

(B) Monitor and record the ~~pilot~~ Pilot gas and ~~purge gas~~ Purge Gas flow to each ~~flare~~ Flare using a separate flow meter or equivalent device approved by the Executive Officer.

~~(9)~~(11) ~~No later than January 30, 2019, for all general service flares:~~

~~(A)~~ The owner or operator of a General Service Flare shall ~~I~~install, operate, calibrate, maintain, and record data from any monitoring systems required by ~~Title 40 of the Code of Federal Regulations~~ 40 CFR Part 63 Subpart CC, section 670 ~~National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries~~ that are not already required by ~~paragraph (g)~~ paragraph (j)(10).

~~(h) Recordkeeping Requirements~~

(12) The owner or operator of a ~~flare~~ Flare shall maintain all records in a manner approved by the Executive Officer for a period of five ~~(5)~~ years for all the information required to be monitored and recorded under ~~paragraphs (g)(3), (g)(4), (g)(5), (g)(6), (g)(7), (g)(9), and subparagraph (g)(8)(B)~~ paragraphs (d)(10), (j)(3), (j)(4), (j)(8), (j)(9), and (j)(11), and subparagraph (j)(10)(B) as applicable, and make such records available to the Executive Officer upon request.

(13) Notwithstanding the provisions in Rule 430 and Rule 2004, the monitoring and recording requirements of paragraphs (j)(1) through (j)(12) shall be applicable during all periods including breakdowns, except as specified in paragraph (j)(6).

(14) Annual Emissions and Throughput Reporting

The owner or operator of a Facility that exceeds the applicable Performance Target in subparagraph (f)(1)(A) or (f)(2)(A), or the annual throughput threshold in subdivision (g) for any calendar year shall submit records of annual sulfur dioxide emissions, annual NOx emissions, or annual throughput, as applicable, in an electronic format approved by the Executive Officer using FENS within 30 days after the end of each calendar year.

(15) Quarterly Reports

The owner or operator of a Facility shall submit a quarterly report in an electronic format approved by the Executive Officer using FENS within 30 days after the end of each quarter. Each quarterly report shall be certified for accuracy in writing by a responsible Facility official and shall include all the following:

(A) The information required to be monitored under paragraphs (j)(3), (j)(4), (j)(8), (j)(9), and subparagraph (j)(10)(B);

(B) Data collected pursuant to paragraph (j)(11) in the first quarterly report after the applicable monitors have been certified;

(C) The total daily and quarterly emissions of criteria pollutants from each Flare and each Flare Event along with all information used to calculate the emissions, which includes standard volumes, higher heating values, and total sulfur concentration of the Vent Gas, Flare Event duration and emission factors used to calculate flare emissions, as follows:

(i) Emissions from Flares shall be calculated using the Emissions Calculation Procedures outlined in Attachment B;

(ii) During all down time periods of the monitoring system, emissions shall be calculated using the Missing Data Substitution Procedures outlined in Attachment B; and

(iii) Each reported value of flow rate, higher heating values or sulfur concentration reported using Data Substitution Procedures in Attachment B, the data substitution method used, and the date the method was approved by the Executive Officer shall be identified, if applicable;

(D) The description of the cause of each Flare Event as analyzed pursuant to paragraphs (d)(5), (d)(6), and/or (d)(10), the category of Flare Event such as Emergency, Shutdown, Startup, Turnaround, Essential Operational Need, or other specific cause(s), and the associated emissions;

(E) Records of annual acoustical or temperature leak survey conducted pursuant to paragraph (d)(4) including identification of all valves inspected, date of inspections, and the name of the person(s) conducting the inspections;

(F) Flare Monitoring System downtime periods, including dates and times and explanation for each period; and

(G) A copy of written notices for all reportable air releases related to any Flare Event, as required by 40 CFR, Part 302 – Designation, Reportable Quantities, and Notification and 40 CFR, Part 355 – Emergency Planning and Notification, if applicable.

(16) Monthly Emissions Reports

Effective January 1, 2025, the owner or operator of a Facility shall submit a monthly report in an electronic format approved by the Executive Officer using FENS within 30 days after the end of each month, flagged as preliminary data in writing by a responsible Facility official and include all the following information that is available to the best of the owner or operator's knowledge:

(A) ~~The i~~Information required to be monitored under paragraph (j)(3);

(B) ~~The d~~Description of the cause of each Flare Event as analyzed pursuant to paragraphs (d)(5), (d)(6), and/or (d)(10);

(C) ~~The c~~Category of each Flare Event such as Emergency, Shutdown, Startup, Turnaround, Essential Operational Need, or other specific cause(s); and

(D) ~~The a~~Associated emissions.

(17) Specific Cause Analysis Reports

The owner or operator of a Facility shall submit Specific Cause Analysis reports as required by paragraph (d)(5) or (d)(6) pursuant to the schedule in paragraph (e)(3), (e)(4), or (e)(5) and a record of completed corrective actions as required by paragraph (e)(9) in an electronic format approved by the Executive Officer using FENS.

(18) If FENS is not available, or if functions within FENS do not allow facilities to enter the necessary information required in paragraphs (j)(14) through (j)(17), the owner or operator of a Facility shall provide the information required in paragraphs (j)(14) through (j)(17) by emailing to Rule1118@aqmd.gov or through an alternative method as approved by the Executive Officer.

(19) For a Facility with no Processing Capacity determined pursuant to Attachment C Table C1, the owner or operator of a Facility shall report to the Executive Officer the Processing Capacity in million barrels for the prior calendar year within 30 days of the end of every calendar year.

(k) Testing and Monitoring Methods

(1) For the purpose of this rule, the test methods listed below shall be used:

(A) The higher (gross) heating value of Vent Gas shall be determined by:

(i) ASTM Method D4809-13, ASTM Method D 3588-98(2011), ASTM Method D4891-13, or other ASTM standard as approved by the Executive Officer, the California Air Resources Board, and the U.S. Environmental Protection Agency; or

(ii) A higher heating value analyzer that meets or exceeds the specifications in Attachment A.

(B) The total sulfur concentration, expressed as sulfur dioxide, shall be determined by:

(i) South Coast AQMD Method 307-91 or ASTM Method D 5504-12, or other ASTM standard as approved by the

Executive Officer, the California Air Resources Board, and the U.S. Environmental Protection Agency; or

(ii) A total sulfur analyzer that meets or exceeds the specifications in Attachment A;

(C) The Vent Gas flow shall be determined by a flow measuring device that meets or exceeds the specifications described in Attachment A, as applicable. The accuracy of all flow meters shall be verified every calendar year but not sooner than six months from the last verification according to the manufacturers' procedures and the results shall be submitted to the Executive Officer within 30 days after the reports are issued.

(2) Visible emissions pursuant to subparagraph (d)(1)(B) shall be determined by US EPA Method 22, 40 CFR Part 60 Appendix A.

(3) Continuous monitoring systems certified under Rule 2011 – Requirements for Monitoring, Reporting and Recordkeeping of Oxides of Sulfur (SOx) Emissions (Rule 2011), Rule 2012 – Requirements for Monitoring, Reporting and Recordkeeping of Oxides of Nitrogen (NOx) Emissions (Rule 2012), Rule 218.2 – Continuous Emission Monitoring System: General Provisions (Rule 218.2), and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications (Rule 218.3), may be used for the monitoring of Vent Gases.

~~(i)~~(l) Flare Event Notification ~~and Reporting~~ Requirements

~~The owner or operator of a flare shall:~~

(1) The owner or operator of a Facility shall ~~Provide~~ maintain a 24-hour telephone service for access by the public for inquiries about ~~flare events~~ Flare Events and ~~. The owner or operator shall~~ provide ~~the Executive Officer in writing~~ the name and number of the initial contact and any contact update in writing to the Executive Officer.

(2) The owner or operator of a Facility shall provide notifications for any Planned or Unplanned Flare Event ~~Notify the Executive Officer~~ via ~~the Web-Based Flare Event Notification System~~ FENS:

(A) ~~w~~Within one hour of ~~from the start of any unplanned flare event with emissions~~ exceeding ~~either~~ at least one of the following thresholds:

(i) 100 pounds of VOC emissions;

(ii) ~~or~~ 500 pounds of sulfur dioxide emissions;~~,~~ or ~~exceeding~~

(iii) 500,000 standard cubic feet of flared ~~vent gas~~ Vent Gas.

(B) Within 24 hours of the end of the Flare Event indicating the Flare Event has ended; and

(C) Within 72 hours of the end of the Flare Event indicating if the Flare Event exceeded the Smokeless Capacity.

(3) Planned Flare Event Notifications

The owner or operator of a Flare shall provide notifications ~~Notify the Executive Officer~~ via ~~the Web-Based Flare Event Notification System~~ FENS at least 24 hours prior to the start of a ~~planned flare event~~ Planned Flare Event with emissions exceeding ~~either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of combusted vent gas~~ any of the following thresholds:~~. Within one hour of the start of a planned flare event, submit a notification via the Web-Based Flare Event Notification System, referencing the notification number assigned to the planned flare event at the time of the original notification.~~

(A) 100 pounds of VOC emissions;

(B) 500 pounds of sulfur dioxide emissions; or

(C) 500,000 standard cubic feet of flared Vent Gas.

(4) Unplanned Flare Event Notifications

If the Unplanned Flare Event lasts longer than 24 hours, the owner or operator of the Facility shall:

(A) End the current Unplanned Flare Event in FENS within 24 hours or at the end of the starting calendar day; and

(B) Generate a new Unplanned Flare Event notification in FENS for every calendar day of flaring afterward.

~~(4)~~(5) The owner or operator of a Flare shall ~~N~~notify the Executive Officer via ~~the Web-Based Flare Event Notification System~~ FENS ~~within~~ no later than one hour after the cumulative daily total amount of ~~flare gas vented~~ Vent Gas from a ~~flare~~ Flare exceeds 100,000 standard cubic feet, if a Flare Event notification has not already been provided for that day pursuant to ~~paragraphs (i)(2) or (i)(3)~~ paragraph (l)(2).

(6) Characterizing and Reporting Flare Events

The owner or operator of a Facility shall characterize and report any Flare Event that exceeds any of the thresholds listed in subparagraph (l)(2)(A) as follows:

(A) A Flare Event due to the Startup of a process unit or equipment that occurs more than 36 hours after the end of an Unplanned Flare Event of the same process unit Shutdown shall be considered a Planned Flare Event;

(B) Flare Events that can be attributed to same process unit(s) or equipment and has more than one start time and stop time within a 24-hour period, shall be considered a continuation of the same event, and not a separate or unique event; and

(C) For an Unplanned Flare Event that continues for more than 24 hours, each calendar day of flaring Vent Gas shall constitute a separate Unplanned Flare Event.

~~(5)~~(7) If ~~the Web-Based Flare Event Notification System~~ FENS is not available, or if functions within ~~the Web-Based Flare Event Notification System~~ FENS do not allow facilities to enter the necessary information required in ~~(i)(2) through (i)(4)~~ paragraphs (l)(2) through (l)(4), the owner or operator of a Facility shall provide the required information ~~then notifications shall be made to~~ by calling 800-CUT-SMOG (800-288-7664).

~~(6) Submit a quarterly report in an electronic format approved by the Executive Officer within 30 days after the end of each quarter. Each quarterly report shall be certified for accuracy in writing by the responsible facility official and shall include the following:~~

~~(A) The information required to be monitored under paragraphs (g)(3), (g)(4), (g)(5), (g)(6), and (g)(9), and subparagraph (g)(8)(C) of this rule. Notwithstanding the January 30, 2019 compliance date in paragraph (g)(9), data collected pursuant to paragraph (g)(9) shall be made available in the first quarterly report after the applicable monitors have been certified.~~

~~(B) The total daily and quarterly emissions of criteria pollutants from each flare and each flare event along with all information used to calculate the emissions, which includes standard volumes, higher heating values and total sulfur concentration of the vent gases, event duration and emission factors. Identify each reported value of flow rate, higher heating values or sulfur concentration reported using Data Substitution Procedures in Attachment B, and identify the data substitution method used and the date the method was approved by the Executive Officer, if applicable.~~

~~(i) Emissions from flares shall be calculated using the Emissions Calculation Procedures outlined in Attachment B: Guidelines for Emissions Calculations.~~

~~(ii) During all down time periods of the monitoring system, emissions shall be calculated using the Missing Data Substitution Procedures outlined in Attachment B: Guidelines for Emissions Calculations.~~

~~(C) The description of the cause of each flare event as analyzed pursuant to paragraphs (c)(6), (c)(7), and (c)(11) and the category of flare event such as emergency, shutdown, startup or essential operational need or other specific cause(s), and the associated emissions.~~

~~(D) Records of annual acoustical or temperature leak survey conducted pursuant to paragraph (c)(5). The record shall include identification of all valves inspected, date of inspections, and the name of the person(s) conducting the inspections.~~

~~(E) Flare monitoring system downtime periods, including dates and times and explanation for each period.~~

~~(F) A copy of written notices for all reportable air releases related to any flare event, as required by 40 CFR, Part 302 – Designation, Reportable Quantities, and Notification and 40 CFR, Part 355 – Emergency Planning and Notification, if applicable.~~

~~(j) Testing and Monitoring Methods~~

~~(1) For the purpose of this rule, the test methods listed below shall be used:~~

~~(A) The higher (gross) heating value of vent gases shall be determined by:~~

~~(i) ASTM Method D4809-13, ASTM Method D 3588-98(2011), ASTM Method D4891-13, or other ASTM standard as approved by the Executive Officer, the California Air Resources Board and the U.S. Environmental Protection Agency; and~~

~~(ii) With a higher heating value analyzer that meets or exceeds the specifications in Attachment A.~~

~~(B) The total sulfur concentration, expressed as sulfur dioxide, shall be determined by:~~

~~(i) District Method 307-91 or ASTM Method D 5504-12, or other ASTM standard as approved by the Executive Officer, the California Air Resources Board and the U.S. Environmental Protection Agency; and~~

~~(ii) With a total sulfur analyzer that meets or exceeds the specifications in Attachment A.~~

~~(C) The vent gas flow shall be determined by a flow measuring device that meets or exceeds the specifications described in Attachment A, as applicable. The accuracy of all flow meters shall be verified every twelve months according to the manufacturers' procedures and the results shall be submitted to the Executive Officer within 30 days after the reports are issued.~~

~~(2) Visible emissions pursuant to paragraph (c)(2) shall be determined by US EPA Method 22, 40 CFR Part 60 Appendix A.~~

~~(3) Notwithstanding paragraph (j)(1), continuous monitoring systems certified under Rule 2011 – Requirements for Monitoring, Reporting and Recordkeeping of Oxides of Sulfur (SOx) Emissions and Rule 2012 – Requirements for Monitoring, Reporting and Recordkeeping of Oxides of Nitrogen (NOx) Emissions, may be used for the monitoring of vent gases.~~

~~(k)~~<u>(m) </u>Exemption<u>s</u>

(1) Notwithstanding <u>the presence of </u>a~~ flare monitoring system~~<u> Flare Monitoring System</u>, consisting of a flow meter, higher heating value analyzer, net heating value analyzer and total sulfur analyzer that is in operation, <u>the owner or operator of a Facility is not required to conduct</u> sampling and analyses of representative samples<u>, as defined in the Facility's FMRP,</u> for higher heating values, net heating values, and total sulfur concentration pursuant to ~~paragraph (g)(3) ~~<u>paragraph (j)(4) </u>~~may not be required ~~for any ~~flare event ~~<u>Flare Event </u>that:

(A) Is a result of a catastrophic event including a major fire or an explosion at the ~~facility ~~<u>Facility </u>such that collecting a sample is infeasible or constitutes a safety hazard~~,~~<u>;</u> or

(B) Constitutes a safety hazard to the sampling personnel at the sampling location approved in ~~the Flare Monitoring and Recording Plan ~~<u>FMRP </u>during the entire~~ flare event~~<u> Flare Event</u>, provided that a sample is collected at an alternative location where it is safe as determined by the ~~facility~~ Facility owner or operator, and~~. T~~ the owner or operator ~~shall~~ demonstrates to the Executive Officer that the sample collected at an alternative location is representative of the ~~flare event~~ Flare Event.

(2) The owner or operator of a Facility may exclude a~~A~~ny sulfur dioxide emissions, any NOx emissions, any visible emissions that exceed limits ~~prohibited~~ in ~~paragraph (c)(10)~~ subparagraph (d)(1)(B), ~~and~~ or any ~~flare tip velocities~~ Flare Tip Velocity that exceeds the applicable limit~~s~~ in ~~subparagraph (c)(3)(A)~~ subparagraph (d)(1)(C) originating from ~~flare events~~ Flare Events caused by external power and/or external water curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters, or acts of war or terrorism ~~shall not count towards either~~ from:

(A) The applicable ~~performance targets~~ Performance Target specified in ~~subdivision (d)~~ subdivision (f), provided the owner or operator of a Facility ~~upon submittal of~~ submits documentation proving the existence of such events and certified in writing by the ~~petroleum refinery~~ Facility official responsible for emission reporting; ~~or~~ and

(B) The prohibitions listed in ~~paragraph (c)(10)~~ paragraph (d)(7).

(3) The owner or operator of a Facility may exclude any Vent Gas and Purge Gas throughput (based on higher heating value) from Flare Events caused by external power and/or external water curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters, or acts of war or terrorism, from the annual throughput in subdivision (g), provided the owner or operator of a Facility submits documentation proving the existence of such events and certified in writing by the Facility official responsible for emission reporting.

ATTACHMENT A

## FLARE MONITORING SYSTEM REQUIREMENTS

The components of each ~~flare monitoring system~~ Flare Monitoring System must meet or exceed the minimum specifications listed below. Components with other specifications may be used provided the owner or operator of a ~~gas flare~~ Facility can demonstrate that the specifications are equivalent and has been approved by the Executive Officer.

### 1. Continuous Flow Measuring Device

The monitor must be sensitive to rapid flow changes~~,~~ and have the capability of reporting both instantaneous velocity and totalized flow. Materials exposed to the ~~flare gas~~ Vent Gas shall be corrosion resistant. If required by the ~~petroleum refinery or the hydrogen production plant~~ Facility, the manufacturer must provide an enclosure with an area classification rating of Class 1, Division 2, Groups A, B, C, D, and is FM and CSA approved. The monitor shall (i) feature automated daily calibrations at low and high ranges, and (ii) shall signal alarms if the calibration error or drift is exceeded, provided that the monitor is equipped with such capability. The volumetric flow measuring device may consist of one or more flow meters, and, as combined, shall meet the following specifications.

| | |
|---|---|
| Velocity Range: | 0.1-250 ft/sec |
| Repeatability: | ± 1% of reading over the velocity range |
| Accuracy: | ± 20% of reading over the velocity range of 0.1-1 ft/s and ± 5% of reading over the velocity range of 1-250 ft/s |
| Installation: | Applicable AGA, ANSI, API, or equivalent standard; hot tap capability. If applicable, the manufacturer must specify the straight-run pipe requirements in terms of the minimum upstream and downstream distances from the nearest flow disturbances to the device |
| Flow Rate Determination: | Must be corrected to one atmosphere pressure and $68^0$ F and recorded as one-minute averages |
| Data Records: | Measured continuously and recorded over one-minute averages. The instrument shall be capable of storing or transferring all data for later retrieval |
| QA/QC: | Shall comply with the flow QA/QC requirements of applicable provisions of ~~District Rule 218.1~~ Rule 218.2 |

and Rule 218.3. An annual verification of accuracy is required~~,~~ and shall be specified by the manufacturer. Note: A flow RATA is generally infeasible due to safety concerns

**2. On/Off Flow Indicator**

The on/off flow indicator is a device which is used to demonstrate the flow of ~~vent gas~~ Vent Gas during a ~~flare event~~ Flare Event~~,~~ and shall meet or exceed specifications as approved by the Executive Officer. The on/off flow indicator setting shall be verifiable.

**3. Data Recording System**

All data as generated by the above flow meters and the on/off flow indicators must be continuously recorded by strip chart recorders or computers. The strip chart must have a minimum chart width of 10 inches, a readability of 0.5% of the span, and a minimum of 100 chart divisions. The computer must have the capability to generate one-minute average data from that which is continuously generated by the flow meters and the on/off limit switch.

**4. Continuous and Semi-continuous Gaseous Stream Higher Heating Value (HHV) Flare Monitoring Systems**

The following is intended to ensure that verifiable, meaningful, and representative data are collected from continuous and semi-continuous gaseous stream HHV ~~flare~~ Flare measurement monitoring devices systems. All procedures are subject to Executive Officer review and approval.

General Requirements:

a. The monitoring system must be capable of measuring HHV within the requirements of the rule.

b. The monitoring system must be capable of adjusting to rapid changes in HHV within a reasonable time meeting the definition of a continuous or semi-continuous monitoring system as defined in the applicable rule and as approved by the Executive Officer.

c. Monitoring system sampling interfaces and analyzers in contact with sample gas must be compatible with sample gases and able to resist flow temperatures and pressures.

d. The sampling inlet system interface must be heated as necessary so as to prevent condensation.

e. Sample gas must be conditioned such that the sample is free of particulate or liquid matter.

f. The sample must flow without impediment through the instrument sampling system sampling interface and analyzer.

g. Use an enclosure with an area classification rating of Class 1, Division 2, Groups A, B, C, D, and is FM or CSA approved. The enclosure must be able to maintain a stable analyzer temperature as required for analyzer performance.

h. The monitoring system must feature automated daily ~~calibrations~~ calibration checks, minimally at mid-range, and preferably at both applicable Federal minimum BTU requirements (low end) and 95% of full scale (high end) ranges at low and high ranges

i. The monitoring system analyzer must include an output compatible with a Data Acquisition System (DAS) or similar system that can process data generated by the analyzer and record the results. A data recorder compatible with analyzer output and capable of recording analyzer output must be supplied with the instrument.

j. Each monitoring system must have a written quality assurance/quality control (QA/QC) plan approved by the Executive Officer and available for ~~District~~ South Coast AQMD inspection.

k. Maintain a maintenance log for each monitoring system.

l. Perform routine maintenance and repair as recommended by the manufacturer or according to a standard operating procedure submitted and approved by the Executive Officer.

m. The placement and installation of monitoring systems is critical for collecting representative information on HHV gas content. Factors that should be considered in placement of a sampling interface include but are not limited to safety, ensuring the sample is representative of the source, ease of placement and access. Sampling interfaces, conditioning systems and enclosures may be shared with other instrumentation, if appropriate.

n. Perform at monitoring system start-up and on an annual basis a relative accuracy test audit (RATA) which is the ratio of the sum of the absolute mean difference between the monitoring system generated data and the value determined using ASTM D1945-03 and ASTM D3588-91, ASTM D 4891-89, or other ASTM standard as approved by the Executive Officer, the California Air Resources Board, and the U.S. Environmental Protection Agency. See ~~rule 218.1 (a)(23)~~ Rule 218.2 and Rule 218.3, as applicable, for calculations.

o. Periodically perform a calibration curve or linearity verification error test according to permitting conditions and or on a schedule approved by the Executive Officer. Typically, this calibration curve will be prepared from standards representing a:

i. 10-30 percent of the measurement range

ii. 40-60 percent of the measurement range

iii. 80-100 percent of the measurement range

p. Analyzers with auto calibration check capability should be checked daily unless a different calibration frequency is approved by the Executive Officer. For analyzers without auto calibration check capability, submit a calibration check frequency request including supporting documentation to the Executive Officer for comment and approval.

i. Daily calibration may be deferred until the end of any Flare Event but not to exceed 72 hours.

ii. In the event of a failed deferred calibration, daily discrete samples shall begin to be collected within 30 minutes if the Flare Event is still occurring and will be used for calculations.

iii. If deferred calibration passes, the normal calibration schedule shall be resumed.

q. Periodically perform a zero-~~-~~-drift test. Allowed zero drift should be consistent with a properly operating system. See ~~rule 218.1 (a)(32)~~ Rule 218.2 and Rule 218.3, as applicable, for calculations.

r. Retain records on the valid data return percentage.

s. Retain records on the availability or up-time of the monitoring system.

t. Retain records on the breakdown frequency and duration of the breakdown.

u. Retain records on excursions beyond quality control limits stated in the QA plan.

**5. Continuous and Semi-continuous Gaseous Stream Total Sulfur Monitoring Systems**

The following is intended to ensure that verifiable, meaningful, and representative data are collected from continuous and semi-continuous gaseous stream sulfur monitoring systems. All procedures are subject to Executive Officer review and approval.

General Requirements

a. The monitoring system must be capable of measuring total sulfur concentration within the requirements of the rule.

b. The monitoring system must be capable of adjusting to rapid changes in sulfur concentration within a reasonable time as defined in the applicable rule and as approved by the Executive Officer.

c. Monitoring system in contact with sample gas must be inert to sulfur gases and resistant to corrosion.

d. The sampling inlet system interface system must be heated as necessary so as to prevent condensation.

e. Sample gas must be conditioned such that the sample is free of particulate or liquid matter.

f. The sample must flow without impediment through the instrument sampling system sampling interface and analyzer.

g. Use an enclosure with an area classification rating of Class 1, Division 2, Groups A, B, C, D, and is FM or CSA approved. The enclosure must be able to maintain a stable analyzer temperature as required for analyzer performance.

h. The monitoring system must feature automated daily calibrations at low and high ranges~~,~~ and shall signal alarms if the calibration error or drift is exceeded.

i. The monitoring system must include a Data Acquisition System (DAS) or similar system that can process data generated by the analyzer and record the results.

j. Each monitoring system must have a written quality assurance/quality control (QA/QC) plan approved by the Executive Officer and available for ~~District~~ South Coast AQMD inspection.

k. Maintain a maintenance log for each monitoring system.

l. Perform routine maintenance as recommended by the manufacturer or according to a standard operating procedure submitted and approved by the Executive Officer.

m. The placement and installation of monitoring systems is critical for collecting representative information on total sulfur gas concentration. Factors that should be considered in placement of a sampling interface include but are not limited to safety, ensuring the sample is representative of the source, ease of placement and access. Sampling interfaces, conditioning systems and enclosures may be shared with other instrumentation, if appropriate.

n. Perform at monitoring system start-up and on an annual basis a relative accuracy test audit (RATA) which is the ratio of the sum of the absolute mean difference between the monitoring system generated data and the value determined using SCAQMD Laboratory Method 307-91, ASTM D5504-01 or other ASTM standard as approved by the Executive Officer, the California Air Resources Board, and the U.S. Environmental Protection Agency. See ~~rule 218.1(a)(23)~~ Rule 218.2 and Rule 218.3, as applicable, for calculations.

Note: Facilities are reminded that there are many critical issues for the collection of representative and monitoring system comparable gas samples destined for Method 307-91 or ASTM D5504-01 analysis.

o. Facilities are strongly encouraged to use calibration gases prepared using a NIST hydrogen sulfide SRM, Nederlands Meetinstituut NMi or a NTRM standard as the primary reference.

p. Periodically perform a calibration curve or linearity verification performed according to permitting conditions and/or on a schedule approved by the Executive Officer. Typically, this calibration curve will be prepared from standards representing:

i. 10 to 30 percent of the measurement range

ii. 40 to 60 percent of the measurement range

iii. 80 to 100 percent of the measurement range

q. Analyzers with auto calibration capability shall be calibrated daily unless a different calibration frequency is approved by the Executive Officer. For analyzers without auto calibration capability, submit a calibration frequency request, including supporting documentation to the Executive Officer for comment and approval.

i. Daily calibration may be deferred until the end of any Flare Event but not to exceed 72 hours.

ii. In the event of a failed deferred calibration, daily discrete samples shall begin to be collected within 30 minutes if the Flare Event is still occurring and will be used for calculations.

iii. If deferred calibration passes, the normal calibration schedule shall be resumed.

r. Seven Day Calibration Error Test shall be performed by evaluating the analyzer performance over seven consecutive days as necessary. The calibration drift should not exceed five percent of the full-scale range.

s. Analyze daily a control or drift test sample or standard. Adequate system analyzer performance is demonstrated by recoveries of 90 to 110 percent of the theoretical amounts for total reduced sulfur species in the test gas.

t. Periodically perform an analyzer blank test to evaluate the presence of analyzer leaks or wear on sample valves and related components. Replace components as necessary to restore the analyzer to nominal function. A blank should yield results below the monitoring plan approved lower measurement range.

u. Periodically perform a zero-drift test. Allowed zero drift should be consistent with a properly operating system analyzer. See ~~rule 218.1(a)(32)~~ Rule 218.2 and Rule 218.3, as applicable, for calculations.

v. Retain records on the valid data return percentage.

w. Retain records on the availability or up-time of the monitoring system.

x. Retain records on the breakdown frequency and duration of the breakdown.

y. Retain records on excursions beyond quality control limits stated in the QA plan.

**Gas Chromatograph (GC) Based System Analyzer Specific Requirements**

a. The following performance tests specific to GC based sulfur analyzers are part of an overall QA program. This list is not all inclusive. The specific performance tests that are required under rule compliance will be based upon analyzer configuration, data requirements, practical concerns such as safety and are subject to approval by the Executive Officer.

i. Whenever a calibration is performed and whenever a calibration drift test is performed, examine retention times for each calibration component. Compare the retention times against historically observed retention times. Retention time drift should be better than within five percent. Compare the retention times to analyzer and DAS parameters such as time gates to ensure compatibility. These parameters including the analysis time may need to be updated on occasion.

ii. Verify daily that the analyzer response drift for individual sulfur species does not exceed ten percent of the control information.

**Total Sulfur Analyzer System Requirements**

a. The following performance tests specific to total sulfur-based analyzers are part of an overall QA program. This list is not all inclusive. The specific performance tests that are required under rule compliance will be based upon instrument analyzer configuration, data requirements, practical concerns such as safety and are subject to approval by the Executive Officer.

i. Verify daily that the analyzer response drift for the concentration of total sulfur, expressed as sulfur dioxide, does not exceed ten percent of the control information.

ATTACHMENT B

**GUIDELINES FOR CALCULATING FLARE EMISSIONS**

The following methods shall be used to calculate ~~flare~~ Flare emissions. An alternative method may be used, utilizing ~~facility~~ Facility-specific data such as monitoring and/or gas composition data, provided it has been approved as equivalent in writing by the Executive Officer.

**1. Emission Calculation Procedures**

~~Petroleum refinery, sulfur recovery plant or hydrogen production facility~~ Facility operators shall use the following equations and emission factors to calculate emissions from ~~vent gas~~ Vent Gas, ~~natural gas~~ Natural Gas, propane, and butane:

**Table B1 – Vent Gas**

| Air Pollutant | Equation(1) | Emission Factor |
|---|---|---|
| ROG | E = V x NHV x EF | 0.66 lb/mmBTU |
| NOx~~1~~(2) | E = V x HHV x EF | 0.068 lb/mmBTU |
| CO | E = V x NHV x EF | 0.31 lb/mmBTU |
| PM10 | E = V x EF | 21 lb/mmSCF |
| SOx | E = V x Cs x 0.1662 | Note ~~(2)~~(3) |

~~**Effective Until January 30, 2019, or Until Monitors Are Installed and Certified That Can Measure Net Heating Value**~~

| ~~**Air Pollutant**~~ | ~~**Equation**~~ | ~~**Emission Factor**~~ |
|---|---|---|
| ~~ROG~~ | ~~E = V x HHV x EF~~ | ~~0.063 lb/mmBTU~~ |
| ~~NOx1~~ | ~~E = V x HHV x EF~~ | ~~0.068 lb/mmBTU~~ |
| ~~CO~~ | ~~E = V x HHV x EF~~ | ~~0.37 lb/mmBTU~~ |
| ~~PM10~~ | ~~E = V x EF~~ | ~~21 lb/mmSCF~~ |
| ~~SOx~~ | ~~E = V x Cs x 0.1662~~ | ~~Note (2)~~ |

Note (1) Where:

E = Calculated ~~vent gas~~ Vent Gas emissions (lbs)

V = Volume flow of ~~vent gas~~ Vent Gas, as measured in million standard cubic feet at 14.7 psia and $68^0$ Fahrenheit, pursuant to Attachment B, Section (2)

HHV = Higher Heating Value, as measured in British Thermal Unit per standard cubic ~~foot~~ feet

NHV = Net Heating Value, as measured in British Thermal Units per standard cubic ~~foot~~ feet

EF = Emission Factor

Cs = The concentration of total sulfur in the ~~vent gas~~ Vent Gas, expressed as sulfur dioxide, as measured in part per million by volume using the methods specified in this rule.

Note ~~(1)~~(2) For ~~vent gas~~ Vent Gas streams of pure hydrogen, only the emission factor for NOx should be used.

Note ~~(2)~~(3) If an approved total sulfur analyzer is used in accordance with this rule, Cs is the concentration of total sulfur in the ~~vent gas~~ Vent Gas, averaged over 15 minutes or less, if the event duration is shorter than 15 minutes.

**Table B2 – Natural Gas**

| Air Pollutant | Equation(1) | Emission Factor (lb/mmSCF) |
|---|---|---|
| ROG | E = V x EF | 7 |
| NOx | E = V x EF | 130 |
| CO | E = V x EF | 35 |
| PM10 | E = V x EF | 7.5 |
| SOx | E = V x EF | 0.83 |

**Table B3 – Propane and Butane**

| Air Pollutant | Equation(1) | Emission Factor (lb/mmBTU) |
|---|---|---|
| ROG | E = V x 3500 x EF | 0.009 |
| NOx | E = V x 3500 x EF | 0.145 |
| CO | E = V x 3500 x EF | 0.082 |
| PM10 | E = V x 3500 x EF | 0.002 |
| SOx(~~1~~2) | E = V x 3500 x EF | 0.047 |

Note (1) Where:

E = Calculated Vent Gas emissions (lbs)

EF = Emission Factor

Note ~~(1)~~(2) If the concentration of total sulfur in the ~~vent gas~~ Vent Gas or in the process streams vented to the ~~flare~~ Flare is measured, the operator shall use E = V x Cs x 0.1662 to estimate the SOx emissions, where Cs is as defined in Table B1 Note (1).

## 2. Flow Rate Determination

**Single On/Off Flow Indicator Switch**

The flow rate setting of the on/off flow indicator switch if the switch is not actuated or the maximum design capacity of the ~~flare~~ Flare for the flow rate for each ~~flare event~~ Flare Event.

**Multiple On/Off Flow Indicator Switch**

a) The flow rate setting of the first stage on/off flow indicator switch if the switch is not actuated.

b) When an on/off switch is actuated assume the flow rate is the flow rate that would actuate the on/off switch set at the next highest flow rate.

c) Use the maximum design capacity of the ~~flare~~ Flare for the flow rate when the on/off switch set for the highest flow rate is actuated.

**Flow Meters Only**

a) Use the recorded flow meter data until the maximum range is exceeded.

b) When the maximum range of the flow meter is exceeded, assume the flow rate is the maximum design capacity of the ~~flare(s)~~ Flare(s), unless the owner or operator demonstrates, and the Executive Officer approves a calculated flow based upon operational parameters and process data that represent the flow during the period of time that the flow exceeded the maximum range of the flow meter.

c) When the flow rate is below the valid lower range of the flow meter, assume the flow rate is at the lower range.

**Combination of Flow Meters and On/Off Flow Indicator Switches**

a) Use the recorded flow meter data until the maximum range is exceeded.

b) When the maximum range of the flow meter is exceeded, assume the flow rate is the flow rate that would actuate the on/off switch set at the next highest flow rate.

c) Use the maximum design capacity of the ~~flare~~ Flare for the flow rate when the on/off switch set for the highest flow rate is actuated.

d) When the flow rate is below the valid lower range of the flow meter, assume the flow rate is at the lower range.

e) When the flow rate is below the valid lower range of the flow meter and the set flow rate of an on/off switch, assume the flow rate is the flow rate that would actuate the on/off switch.

## ~~2.~~3. Data Substitution Procedures

For any time period for which the ~~vent gas~~ Vent Gas flow, the higher heating value or the total sulfur concentration, expressed as sulfur dioxide, are not measured, analyzed and recorded pursuant to the requirements of this rule, unless the owner or operator of a ~~petroleum refinery, sulfur recovery plant or hydrogen production plant~~ Facility demonstrates using verifiable records of ~~flare~~ Flare water seal level and/or other parameters as approved by the Executive Officer in ~~the Flare Monitoring and Recording Plan~~ FMRP or ~~the Revised Flare Monitoring and Recording Plan~~ revised FMRP that no ~~flare event~~ Flare Event occurred during the period these parameters were not measured, analyzed or recorded, the operator shall substitute and report the following values:

a) If the flow rate is not measured or recorded for any ~~flare event~~ Flare Event, the totalized flow shall be calculated from the methodology in ~~section~~ Sections (2)(a)(i) or (2)(a)(ii) below, unless the Executive Officer approves the method specified in Section (2)(a)(iii).

i) The totalized flow shall be calculated from the product of the ~~flare event~~ Flare Event duration and the estimated flow rate. The flow rate shall be calculated using the following equation for the period of time the flow meter was out of service:

$$\cancel{\mathrm{FR} = \mathrm{Max.FR} - 0.5 \times (\mathrm{Max.FR} - \mathrm{Avg.FR})}$$

$$\mathrm{FR} = \mathrm{FR}_{Max} - 0.5 \times (\mathrm{FR}_{Max} - \mathrm{FR}_{Avg})$$

Where:

FR = Estimated Flow Rate (standard cubic feet per minute)

~~Max~~ $\mathrm{FR}_{\mathrm{Max}}$ = Maximum flow rate that was measured and recorded for that ~~flare~~ Flare during the previous 20 quarters preceding the subject ~~flare event~~ Flare Event. This maximum value is based on the average flow rate during an individual ~~flare event~~ Flare Event, not an instantaneous maximum value.

~~Avg~~ $FR_{Avg}$ = Average flow rate for all measured and recorded flow rates for all sampled ~~flare events~~ Flare Events for that ~~flare~~ Flare, during the previous 20 quarters preceding the subject ~~flare event~~ Flare Event.

The duration of a ~~flare event~~ Flare Event during periods when the flow meter is out of service shall be determined using an alternate method approved by the Executive Officer in ~~the Flare Monitoring and Recording Plan~~ FMRP or ~~Revised~~ revised ~~Flare Monitoring and Recording Plan~~FMRP.

In the absence of an approved alternate method to determine the duration of the ~~flare event~~ Flare Event during periods when the flow meter is out of service, the operator shall report the ~~flare~~ Flare to be venting for the entire time the flow meter is out of service.

ii) If the flow rate data was not measured or recorded for a period of time less than or equal to15 consecutive minutes during any Flare Event, the flow rate shall be calculated using the equation in Section (2)(a)(i), and maximum flow rate ($FR_{Max}$) and average flow rate ($FR_{Avg}$) that were measured and recorded for that Flare Event during the one hour preceding and the one hour following the period of time the flow rate data is not measured or recorded.

~~ii)~~iii) Alternate methods using recorded and verifiable operational parameters and/or process data, including reference to similar events that have previously occurred, approved by the Executive Officer to be representative of the volume of ~~vent gas~~ Vent Gas, may be used to determine the flow rate in lieu of the method specified above.

b) If the higher heating value is not measured or recorded for any ~~flare event~~ Flare Event pursuant to the requirements of this rule, the higher heating value shall be calculated from the methodology in ~~section~~ Section (2)(b)(i) or (2)(b)(ii) below, unless the Executive Officer approves the method specified in Section (2)(b)(iii).

i) The higher heating value shall be calculated using the following equation for the period of time this parameter was not measured or recorded:

$$\cancel{HHV = Max\ HHV - 0.5 \times (Max\ HHV - Avg\ HHV)}$$

$$HHV = HHV_{Max} - 0.5 \times (HHV_{Max} - HHV_{Avg})$$

Where:

HHV = Estimated higher heating value (Btu/scf)

~~Max~~ $HHV_{Max}$ = Maximum ~~HHV~~ higher heating value measured and recorded for that ~~flare~~ Flare during the previous 20 quarters preceding the ~~flare event~~ Flare Event.

~~Avg~~ $HHV_{Avg}$ = Average ~~value of all HHV~~ higher heating value measured and recorded for that ~~flare~~ Flare for all sampled ~~flare events~~ Flare Events during the previous 20 quarters preceding the ~~flare event~~ Flare Event.

ii) If the higher heating value data was not measured or recorded for a period of time less than or equal to15 consecutive minutes during any Flare Event, the higher heating value shall be calculated using the equation in Section (2)(b)(i), and maximum higher heating value ($HHV_{Max}$) and average higher heating value ($HHV_{Avg}$) that were measured and recorded for that Flare Event during the one hour preceding and the one hour following the period of time the higher heating value data is not measured or recorded.

~~ii)~~iii) Alternate methods using recorded and verifiable operational parameters, sampled data, and/ or process data, including reference to similar events that have previously occurred, approved by the Executive Officer to be representative of the HHV of the ~~vent gas~~ Vent Gas, may be used to determine the HHV in lieu of the method specified above.

c) If the total sulfur concentration, expressed as sulfur dioxide, is not measured or recorded for any ~~flare event~~ Flare Event pursuant to the requirements of this rule, it shall be calculated from the methodology in ~~section~~ Sections (2)(c)(i) or (2)(c)(ii) below, unless the Executive Officer approves the method specified in Section (2)(c)(iii).

i) The total sulfur concentration, expressed as sulfur dioxide, shall be calculated using the following equation for the period of time this parameter was not measured or recorded:

$$\cancel{SFE = Max\ SFE - 0.5 \times (Max\ SFE - Avg\ SFE)}$$

$$C_{Sulfur} = C_{Sulfur,Max} - 0.5 \times (C_{Sulfur,Max} - C_{Sulfur,Avg})$$

Where:

~~SFE~~$C_{Sulfur}$ = Estimated total sulfur concentration, expressed as sulfur dioxide (ppmv)

~~Max SFE~~$C_{Sulfur,Max}$ = Maximum total sulfur concentration, expressed as sulfur dioxide, measured and recorded for that ~~flare~~ Flare during the previous 20 quarters preceding the ~~flare event~~ Flare Event.

~~Avg SFE~~$C_{Sulfur,Avg}$ = Average ~~value of all~~ total sulfur concentrations measured and recorded for that ~~flare~~ Flare for all sampled ~~flare events~~ Flare Events during the previous 20 quarters preceding the ~~flare event~~ Flare Event.

ii) If total sulfur concentration data is not measured or recorded for a period of time less than or equal to 15 consecutive minutes during any Flare Event, the total sulfur concentration shall be calculated using the equation in Section (2)(c)(i), and maximum total sulfur concentration ($C_{Sulfur,Max}$) and average total sulfur concentration ($C_{Sulfur,Avg}$) that were measured and recorded for that Flare Event during the one hour preceding and the one hour following the period of time the sulfur concentration data is not measured or recorded.

~~ii)~~iii) Alternate methods using recorded and verifiable operational parameters, sampled data, and/ or process data, including reference to similar events that have previously occurred, approved by the Executive Officer to be representative of the total sulfur concentration of the ~~vent gas~~ Vent Gas, expressed as sulfur dioxide, may be used to determine the total sulfur concentration in lieu of the method specified above.

ATTACHMENT C

**PROCESSING CAPACITY OF REFINERIES AND PRODUCTION CAPACITY OF HYDROGEN PRODUCTION PLANTS**

This attachment provides Processing Capacity numbers for Refineries and Hydrogen Production Capacity numbers for Hydrogen Production Plants as of [*Date of Rule Adoption*].

Effective from [*Date of Rule Adoption*], the owner or operator of Facilities shall determine the applicable capacity pursuant to either of the following clauses, whichever the latest:

(i) As listed in Table C1 or Table C2; or

(ii) As listed in the Facility's Title V permit, the Facility's FMRP, or the California Energy Commission's list of California Oil Refinery Locations and Capacities, if applicable, on [*Date of Rule Adoption*], or as reported pursuant to paragraph (j)(19).

**Table C1 – Processing Capacity of Refineries**

| Facility | Processing Capacity (Barrels per Day) |
|---|---|
| **AltAir Paramount** | Pursuant to Paragraph (j)(19) |
| **Chevron USA Inc.** | 269,000 |
| **Marathon (Carson, Wilmington, SRP)** | 363,000 |
| **Phillips 66 (Carson, Wilmington)** | 139,000 |
| **Torrance Refining Co.** | 160,000 |
| **Valero** | 85,000 |

**Table C2 – Production Capacity of Hydrogen Production Plants**

| Hydrogen Production Plant | Hydrogen Production Capacity (Million Standard Cubic Feet per Day) |
|---|---|
| **Air Liquide** | 90 |
| **Air Product – Carson** | 96 |
| **Air Product - Wilmington** | 88 |
| **Chevron USA Inc.** | 72 |

ATTACHMENT D

## GUIDELINES FOR CALCULATING MITIGATION FEES FOR PERFORMANCE TARGETS EXCEEDANCE

This attachment provides the methodology to calculate the mitigation fees that the owner or operator of a Facility shall pay to South Coast AQMD when any Performance Target is exceeded in any single year.

**1. Calculations for Facility-Specific Sulfur Dioxide Performance Target**

The owner or operator of a Refinery or Sulfur Recovery Plant shall calculate the Facility-specific sulfur dioxide Performance Target based on the Processing Capacity as listed in the California Energy Commission's list of California Oil Refinery Locations and Capacities for that calendar year, or as reported pursuant to paragraph (j)(19), using the following equation:

$$\text{Facility Specific Sulfur Dioxide Performance Target [Tons]} = \text{Applicable Performance Target}\left[\frac{\text{Ton}}{\text{Million Barrels}}\right] \times \text{Processing Capacity [Million Barrels]}$$

Where:

Applicable Performance Target = As specified in Table 1 – Performance Target Schedule for Sulfur Dioxide

**2. Calculations for Facility-Specific NOx Performance Target**

The owner or operator of a Hydrogen Production Plant shall calculate the Facility-specific NOx Performance Target based on the Hydrogen Production Capacity, using the following equation:

$$\text{Facility Specific NOx Performance Target [Pounds]} = 0.3\left[\frac{\text{Pound}}{\text{Million Standard Cubid Feet}}\right] \times \text{Hydrogen Production Capacity [Million Standard Cubic Feet]}$$

**3. Calculations for Baseline Mitigation Fees**

The baseline mitigation fees shall be calculated according to the following schedule:

a) If excess sulfur dioxide emissions or NOx Emissions are no more than ten percent of the Facility-specific Performance Target, $39,000 per ton of the sulfur dioxide emissions or NOx Emissions in excess of the Facility-specific Performance Target;

b) If excess sulfur dioxide emissions or NOx Emissions are greater than ten percent but no more than twenty percent of the Facility-specific Performance Target, $79,000 per ton of the sulfur dioxide emissions or NOx Emissions in excess of the Facility-specific Performance Target; or

c) If excess sulfur dioxide emissions or NOx Emissions are greater than twenty percent of the Facility-specific Performance Target, $158,000 per ton of the sulfur dioxide emissions or NOx Emissions in excess of the Facility-specific Performance Target.

**4. Calculations for Adjusted Mitigation Fees**

The baseline mitigation fees shall be adjusted for the calendar year that the Performance Target was exceeded to account for any change in the consumer price index (CPI), according to the following equation:

$$\text{Adjusted Mitigation Fees} = \text{Baseline Mitigation Fees} \times \frac{\text{Reporting Year CPI}}{\text{2022 CPI}}$$

Where:

| | | |
|---|---|---|
| Adjusted Mitigation Fees | = | Mitigation fees due to pay to South Coast AQMD for exceeding the Performance Target, in USD |
| Baseline Mitigation Fees | = | Mitigation fees, as calculated pursuant to Attachment D, Part (3), in USD |
| Reporting Year CPI | = | CPI for the calendar year that the Performance Target was exceeded, if available, or the most recently available CPI, as determined by State of California Department of Industrial Relations |
| 2022 CPI | = | 319.224 |

**ATTACHMENT G**

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

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Final Staff Report

# Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

April 2024


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Planning, Rule Development, and Implementation
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Senator (Ret.)
Senate Rules Committee Appointee

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<u>EXECUTIVE OFFICER:</u>

WAYNE NASTRI

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# EXECUTIVE SUMMARY

Rule 1118 – Control of Emissions from Refinery Flares (Rule 1118) was originally adopted by the South Coast Air Quality Management District (South Coast AQMD) Governing Board on February 13, 1998, and was amended three times since adoption, in 2005, 2017, and 2023. The intent of Rule 1118 is to monitor and record data on refinery and related flaring operations, and to control and minimize emissions from refinery flares. Rule 1118 establishes requirements for flares operated at petroleum refineries and related operations including requirements to submit notifications and reports, monitor emissions, meet emissions targets, and maintain a public inquiry hotline.

As part of the amendment to Rule 1118 in 2005, all refineries in South Coast AQMD were required to have flare gas recovery systems (FGR) installed, and since then the amount of flaring and flaring emissions has been reduced considerably. However, refineries continue to experience numerous flaring events each year. While most events have only a minor release of emissions, some are significant events that result in substantial emissions of many pollutants, along with dark plumes of smoke. The last major amendment to Rule 1118 was the 2017 amendment, which was the first phase of a planned two-phase amendment. The first phase primarily focused on establishing mechanisms to gather more information through scoping documents prepared by the owners and operators of regulated facilities. The current amendment is the second phase, which seeks further emission reductions from flares operated at petroleum refineries and related operations. Additionally, in 2017, Assembly Bill 617 (AB 617) was signed into state law and required strategy development to reduce toxic air contaminants and criteria pollutants in overburdened communities. During the development of the AB 617 Community Emission Reductions Program (CERP)[1] for the Wilmington, Carson, West Long Beach (WCWLB) community, community members expressed concern about refinery flaring events and the associated emissions.

Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares (PAR 1118) is the second phase of the planned two-phase rule amendment and seeks to achieve further emission reductions from refinery flares. PAR 1118 relies upon the information gathered from the scoping documents submitted after the 2017 amendment and South Coast AQMD staff's investigations on flare emission reductions. PAR 1118 will achieve most of the AB 617 CERP air quality priorities for WCWLB community by establishing a more stringent sulfur dioxide performance target, a new performance target for oxides of nitrogen emissions from clean service flares at hydrogen production plants, and a throughput threshold for liquified petroleum gas (LPG) clean service flares at refineries. PAR 1118 is estimated to achieve a 50 percent reduction in sulfur dioxide which will fulfill the sulfur dioxide emission goal of AB 617 CERP for WCWLB community.

As part of PAR 1118, staff is recommending to:

1. Lower annual $SO_2$ performance target threshold for all facilities;
2. Establish a new annual performance target for oxides of nitrogen (NOx) for clean service flares at hydrogen production plants;
3. Include new requirements for LPG clean service flares at refineries;
4. Adjust mitigation fees annually based on the most recent consumer price index (CPI); and

[1] South Coast AQMD AB 617 CERP for Wilmington, Carson, West Long Beach Community: https://www.aqmd.gov/docs/default-source/ab-617-ab-134/steering-committees/wilmington/cerp/final-cerp-wcwlb.pdf?sfvrsn=8

5. Update and standardize reporting requirements for facilities through the flare event notification system (FENS).

PAR 1118 was developed through a public process that included five Working Group Meetings and will include a Public Workshop and a Public Consulting session for the community members.

# CHAPTER 1 : BACKGROUND

**INTRODUCTION**

**REGULATORY BACKGROUND**

**AFFECTED INDUSTRIES**

**AFFECTED EQUIPMENT**

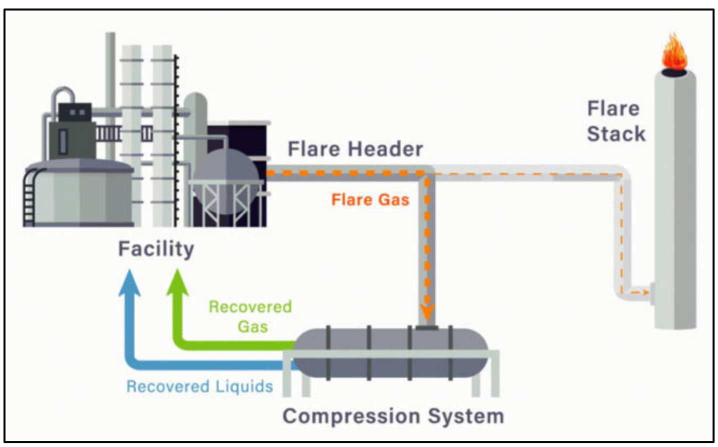
**PUBLIC PROCESS**

### *INTRODUCTION*

Rule 1118 – Control of Emissions from Refinery Flares (Rule 1118) was originally adopted by the South Coast Air Quality Management District (South Coast AQMD) Governing Board on February 13,1998. The intent of Rule 1118 is to control and minimize emissions from refinery flares. Rule 1118 establishes requirements for flares operated at petroleum refineries and related operations including requirements to submit notifications and reports, monitor emissions, meet emissions targets, and maintain a public inquiry hotline.

In recent years several incidents at some refineries, including offsite power disruptions and onsite process unit breakdowns, resulted in flare events and increased emissions that impacted the air quality of neighboring communities. The amount of flaring that has occurred in recent years has varied, with some refineries flaring more than others. As part of the amendment to Rule 1118 in 2005, all refineries in the South Coast AQMD were required to have flare gas recovery (FGR) systems installed, and since then the amount of flaring and flaring emissions has been reduced considerably.

Vent gases generated during the refining process (typically hydrocarbons) are often sent to the FGR system. The figure below demonstrates a flare gas recovery system at a refinery and its different components. FGR systems recover vent gas and inject it into the refinery's fuel gas system for use in other processes, such as steam boilers. Flaring occurs when the FGR system is unable to handle the amount or type of gases being directed into the system, whether due to unplanned flare events like external power disruptions or onsite emergencies, or from planned flare events like refinery turnarounds. Under such circumstances, FGR systems route the extra vent gas to the flare where it is discharged into the atmosphere at the flare tip to avoid unsafe over-pressurization. These gases are combusted at the flare tip to reduce associated emissions and avoid possible buildup of combustible gases. While this simplified explanation describes why flaring occurs, flaring events at different refineries or related operations are caused by a variety of factors and due to the complexity of each refinery, the owner or operator of facilities have varying abilities to prevent or handle the excess vent gas being generated during those events.




(Image Courtesy: Politico)

**Figure 1-1. Refinery Flare Gas Recovery System**

Refineries continue to experience numerous flaring events each year. While most events have only a minor release of emissions, some are significant events that result in substantial emissions of many pollutants, along with dark plumes of smoke. Proposed Amended Rule 1118 – Control of

Emissions from Refinery Flares (PAR 1118) seeks to achieve further emission reductions from refinery flares. This amendment will implement the second phase of the planned two-phase rule amendment and will achieve most of the air quality priorities that were set forth by Assembly Bill 617 (AB 617) Community Emission Reductions Program (CERP) for WCWLB community.

The amendments being sought or considered in PAR 1118 include:

1. Lower annual sulfur dioxide ($SO_2$) performance target threshold for all facilities;
2. New annual oxides of nitrogen (NOx) performance target for clean service flares at hydrogen production plants;
3. New requirements for clean service flares at refineries (i.e., flares for liquified petroleum gas tanks);
4. Adjusted mitigation fees annually based on the most recent consumer price index (CPI); and
5. Updated and standardized reporting requirements for facilities through the flare event notification system (FENS).

Each of these proposed amendments is described in more detail in this staff report.

### *REGULATORY BACKGROUND*

Rule 1118 was originally adopted by South Coast AQMD Governing Board on February 13, 1998. The intent of the rule is to minimize emissions from refinery flares and require petroleum refineries and related operations to monitor, record, and report flare emissions data. The rule was amended three times since adoption, in 2005, 2017, and 2023.

#### *2005 Amendment*

When the rule was adopted in 1998, the Governing Board directed staff to analyze the monitoring data submitted by the refineries and related facilities from October 1, 1999, through December 31, 2003. Staff presented the findings in a report to the South Coast AQMD Governing Board on September 3, 2004, which concluded that refinery flaring was significant enough to warrant the implementation of controls to reduce emissions. The report identified that the prevention of flaring of excess fuel gas, the elimination of leaks from pressure relief devices, and reductions of routine flaring were the most effective approaches to reduce emissions from refinery flaring. The report also concluded that the flare reduction goals can be achieved with the installation of flare gas recovery systems and gas treating systems, expanding the capacities of existing flare gas recovery systems and existing gas treatment systems, and addressing leaks from pressure relief valves. Furthermore, the report also recommended improvements in the measurement of flare vent gas flows and installations of continuous monitoring systems to measure the total sulfur concentration and the higher heating value of the flared gas, as well as standardized methodologies to calculate vent gas flow rate, emissions, and missing data.

The 2005 amendments to Rule 1118 implemented the objectives identified in the report and established a $SO_2$ performance target of 0.5 ton per million barrel of crude processing capacity.

#### *2017 Amendment*

In 2012, the United States Environmental Protection Agency (U.S. EPA) initiated a review of its Refinery Regulations, New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT) I and MACT II regulations for refinery process units and ancillary equipment operations which included the operation of refinery flares. U.S. EPA's review resulted in updates to the requirements in the Refinery Sector Rule, which was finalized in December 2015. The updated federal requirements for flaring focused on reducing significant flaring events and ensuring that when a flaring event does occur, combustion is as efficient as possible to reduce associated emissions. Furthermore, in December 2016, U.S. EPA also revised its Air Pollution Emission Factors (AP-42) guidance for estimating volatile organic compound (VOC) emissions from flaring events stating that using the total hydrocarbon (THC) emissions factor may not be appropriate for reporting VOC emissions when an emissions factor exists for VOC. The updated AP-42 emission factor for VOC emissions was increased about 10-fold (from 0.063 to 0.66 pound of VOC per million British thermal units or lb/MMBtu) which is applicable to "well-operated flares achieving at least 98 percent destruction efficiency."

The 2017 amendment consisted of a phased approach; staff proposed to amend the rule in two rulemaking phases, with Phase II of rulemaking to occur later based on the information gathered in Phase I. Phase I primarily focused on establishing mechanisms to gather more information through scoping documents prepared by the owner and operators of regulated facilities and updated the rule for consistency with federal requirements. Phase I consisted of the following changes to the rule:

- Harmonizing Rule 1118 with the most significant provisions from US EPA's 2015 Refinery Sector Rule update regarding flares, including new prohibitions on certain types of flaring events;
- Aligning Rule 1118 with AB 617 CERP requirements;
- Requiring all facilities subject to Rule 1118 to prepare a Scoping Document that evaluates the feasibility of eliminating or minimizing planned and unplanned flaring events;
- Setting the requirements for regulated facilities to submit notifications and reports, monitor emissions, meet emissions targets, and maintain a public inquiry hotline;
- Removing the $4 million annual cap on mitigation fees paid by facilities for flaring;
- Updating the VOC emission factors based on EPA's updated AP-42 guidance;
- Updating and clarifying reporting requirements for facilities which are required to submit notifications, reports, monitor emissions, meet emission targets, and maintain a public inquiry hotline.

**South Coast AQMD Follow-up Actions to 2017 Amendment to Rule 1118**

As part of the Phase I amendment to Rule 1118 in 2017, staff incorporated the most significant portions of the U.S. EPA Refinery Sector Rule (RSR) along with other proposed amendments. Staff postponed full incorporation of the remainder of the RSR to Phase II of the proposed rulemaking due to its complexity; however, staff is no longer proposing to incorporate all the remaining RSR requirements into Rule 1118 during this second phase of amendments. The requirements of RSR are being implemented by the permitting staff by incorporating the requirements into the facilities' Title V permits. This is a better approach to assure compliance with the RSR requirements. Staff proposed to include some additional references to RSR in PAR 1118 where it helps clarify rule provisions.

Upon amendment of Rule 1118 in 2017, the South Coast AQMD Governing Board also directed staff to initiate the second phase of rulemaking on Rule 1118 in 2018, and draft amendments to Rule 1118 that would further reduce emissions from flaring for the Board's consideration no later than January 31, 2020. However, due to shifting priorities and limited resources, the rule amendment was delayed.

### *2023 Amendment*

On September 21, 2022, U.S. EPA announced a limited approval and limited disapproval of the 2017 amendments to Rule 1118, effective on October 24, 2022.

The limited approval stated that Rule 1118 improves the state implementation plan (SIP) and is largely consistent with the relevant Clean Air Act (CAA) requirements. However, U.S. EPA proposed a limited disapproval stating that Rule 1118 paragraph (j)(1) and Attachment A paragraphs (4)(n) and (5)(n) provide "unbounded director's discretion" and as a result, the rule does not satisfy the requirements of CAA section 110. The 2017 version of Rule 1118 included several instances where the Executive Officer had the sole authority to approve American Society for Testing and Materials (ASTM) methods without further specificity regarding how this authority will be exercised. U.S. EPA stated that would undermine the enforceability of the submission, constitutes a SIP deficiency, and conflicts with CAA Section 110.

To address the U.S. EPA limited disapproval, staff proposed amendments to Rule 1118 to include a requirement that in addition to the South Coast AQMD's Executive Officer, the California Air Resources Board (CARB) and U.S. EPA must also approve ASTM standards not included in the rule. Staff could not delay the amendment as the CAA specifies that regions must attain the National Ambient Air Quality standards (NAAQS) by specific dates or face the possibility of sanctions by the federal government and other consequences, including but not limited to increased permitting fees, stricter restrictions for permitting new projects, and the loss of federal highway funds. South Coast AQMD had to address the announced deficiencies by April 24, 2024 (i.e., 18 months since the disapproval effective date), otherwise sanctions would be imposed. Thus, staff conducted a limited amendment to the rule to address U.S. EPA's disapproval and avoid sanctions. The 2017 version of Rule 1118 was amended by the South Coast AQMD Governing Board on January 6, 2023.

### *Assembly Bill 617*

AB 617 was initially signed into law in 2017 as a statewide strategy to reduce toxic air contaminants and criteria pollutants in designated environmental justice communities, through establishing community-focused and community-driven actions to reduce air pollution and improve public health. Currently, there are six designated AB 617 communities in South Coast AQMD jurisdiction, as follows:

- Wilmington, Carson, West Long Beach Community (WCWLB)
- San Bernardino, Muscoy Community (SBM)
- East Los Angeles, Boyle Heights, West Commerce Community (ELABHWC)
- Southeast Los Angeles Community (SELA)
- Eastern Coachella Valley Community (SLA)
- South Los Angeles Community (ECV)

Most of the regulated facilities subject to Rule 1118 are located in WCWLB community.

### *AB 617 Community Emissions Reduction Plans (CERPs)*

AB 617 CERPs seek to address the community's highest air quality priorities with actions that reduce air pollution emissions from sources within the local community and that provide a blueprint for achieving reductions in air pollution exposure to people in each community. The plan for WCWLB community started in 2019 and is expected to be implemented over several years.

WCWLB community identified flare emissions from refineries as one category of the air quality priorities to be addressed by that CERP. Action items for Rule 1118 are as follow:

- Lower performance targets and/or adjust mitigation fees
- Increase capacity of vapor recovery systems to store gases during shutdowns
- Header modifications for gas diversion with process controls
- Back-up power systems for key process units
- Remote optical sensing for flare emission characterization
- Lower-emission flaring technologies
- Additional flare minimization plans

The implementation period of the actions in the WCWLB community CERP is expected to be approximately five years from 2019. PAR 1118 will address the CERP actions that were deemed technically feasible and is anticipated to be adopted within the five-year period specified in the CERP.

### *SCOPING DOCUMENTS*

Since a facility operator understands their process the best, the 2017 amendments to Rule 1118 required the operator of each facility to prepare and submit a Scoping Document within 12 months of rule amendment. Facility operators and owners were required to conduct an evaluation of the technical feasibility, approximate cost, and timing constraints to implement control options for minimizing or avoiding planned and unplanned flaring events. Each facility was required to evaluate two alternatives to eliminate planned flaring events and assess how to reduce emissions from planned flaring events to a level beyond 0.5 ton of $SO_2$ per million barrels of crude processing capacity. The scoping documents were reviewed and evaluated for further potential amendments.

### *AFFECTED FACILITIES AND EQUIPMENT*

PAR 1118 affects 12 facilities, all of which are located within Los Angeles County. The facilities include eight petroleum refining facilities, three hydrogen production plants, and one sulfur recovery plant, with a total of 31 existing flares affected by this proposed rule, as listed in the table below. Three flares are clean service flares operating at refineries LPG tank stations, four flares are clean service flares operating at three hydrogen production plants and one petroleum refinery, and the others are general service flares that are being operated at refineries and sulfur recovery plants.

**Table 1-1. Regulated Facilities and Flares by PAR 1118**

| Facility Type | Facility Name | Number of Flares |
|---|---|---|
| Hydrogen Production Plant | Air Liquide | 1 |
| | Air Products Carson | 1 |
| | Air Products Wilmington | 1 |
| Refinery | Chevron Products Company | 6 |
| | Paramount Petroleum | 1 |
| | Phillips 66 Carson | 2 |
| | Phillips 66 Wilmington | 4 |
| | Tesoro Carson | 5 |
| | Tesoro Wilmington | 2 |
| | Ultramar/Valero | 4 |
| | Torrance Refinery | 3 |
| Sulfur Recovery Plant | Tesoro Sulfur Recovery Plant | 1 |
| **TOTAL** | **12** | **31** |

### *Site Visits to Regulated Facilities*

Staff conducted site visits to all regulated facilities between November 3, 2022, and January 18, 2023. Staff observed that each facility is unique in operation and structure. Seven out of twelve facilities operate clean service flares, including four clean service flares located at hydrogen production plants and three liquified petroleum gas (LPG) clean service flares. Staff noted that two out of three LPG clean service flare are operated in a manner where a continuous gas stream is being combusted in the flare.

Staff also noted that all facilities have FGR systems. Generated vent gases during the refining process are often sent to FGR to be recovered and injected back into the refinery's fuel gas system for use in other processes. Flaring occurs when the FGR system is unable to handle the amount or type of vent gas being directed into the system, and as a result, vent gas is routed to the flare to avoid over-pressurization. Flares operate as a safety mechanism and control device at the facilities. Vent gas is combusted at flare tip to reduce emissions and avoid the potential build-up of combustible gas. One limitation to recover the vent gas and route it to the refinery's fuel gas system is the facility's potential capability to use all the recovered vent gas. Facilities that can utilize a significant quantity of excess vent gas generally have the least amount of flaring. Larger facilities and facilities that operate gas turbine generators, which have the ability to combust a large volume of gas, have more flexibility to re-route vent gas from flare to their flare gas system.

Staff discussed the performance of FGR systems with industry stakeholders during their visits to regulated facilities. Over years, many facilities have reduced flaring emissions through operational changes, including slowing down shutdown process, increased reliability of process equipment, and renting thermal oxidizer to combust excess gases during scheduled shutdown and subsequent startup operations.

From the visits to hydrogen production plants, staff discussed different causes that lead to flaring at these facilities with the industry stakeholders. Most flaring at hydrogen production plants is originated from customer kick back, which is challenging for the hydrogen production plants to plan for or manage.

The following figure shows the dates of the site visits.

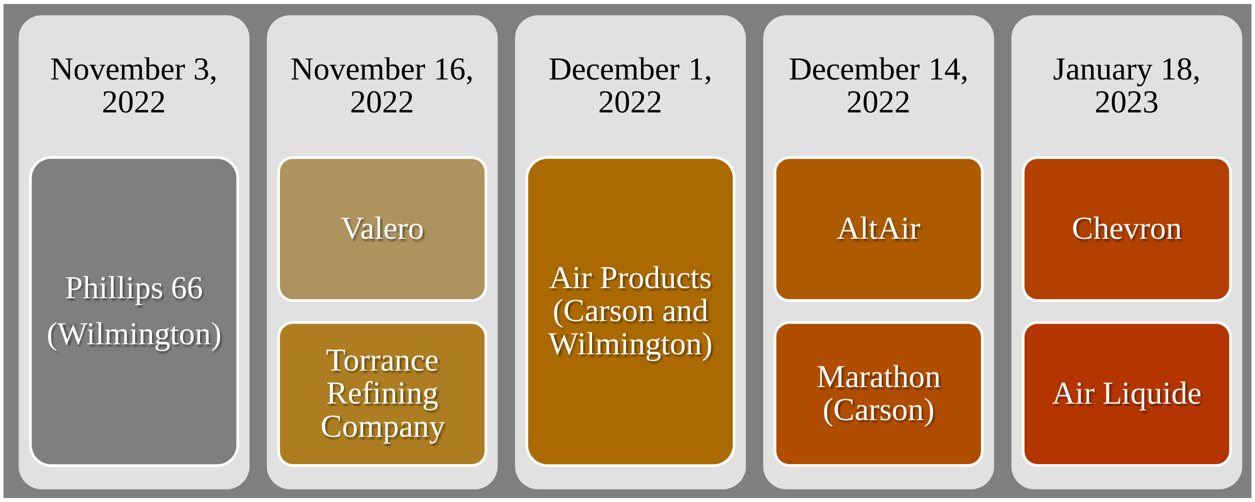



**Figure 1-2. Staff's Site Visits to Regulated Facilities by PAR 1118**

### *PUBLIC PROCESS*

PAR 1118 was developed through a public process that included a series of Working Group Meetings. The table below summarizes the public meetings held throughout the development of PAR 1118 and provides a summary of the key topics discussed at each of the meetings. Staff began the rule development process in July 2022 and has conducted five Working Group Meetings to date. The Working Group is composed of affected facilities, environmental and community representatives, public agencies, consultants, equipment vendors, and interested parties. The purpose of the Working Group Meetings was development of the proposed amendments and emission controls for PAR 1118, to provide all stakeholders an opportunity to discuss details of the proposed amendments, and to listen to stakeholder concerns with the objective of building consensus and resolving any issues. Staff also held individual stakeholder meetings as needed and conducted several site visits to the affected facilities.

**Table 1-2. Summary of Public Meetings**

| Date | Meeting Title | Highlights |
|---|---|---|
| July 21, 2022 | Working Group Meeting #1 | • Rule development process<br>• Background and regulatory commitments<br>• Progress since the previous rule amendment |
| October 26, 2022 | Working Group Meeting #2 | • Analysis of historical flare events data<br>• Limited proposed amendment to Rule 1118 to address EPA's limited SIP disapproval (WGM served as Public Workshop)<br>• Presentation by representatives from R.A. Nichols Engineering (RANE) on their vapor storage technology |

| Date | Meeting Title | Highlights |
|---|---|---|
| November 3, 2022 – January 18, 2023 | | South Coast AQMD staff's site visits to regulated facilities by Rule 1118 |
| December 2, 2022 | | Set Hearing |
| December 2, 2022 | | Released Draft Rule Language |
| January 6, 2023 | | Public Hearing |
| April 26, 2023 | Working Group Meeting #3 | • Follow-up to the comment letter received from Coalition of Environmental Groups on April 13, 2023<br>• Summary of staff's site visits to regulated facilities by Rule 1118<br>• Evaluation of flare events data<br>• Evaluation of flaring at clean service flares and alternatives<br>• Discussion of flaring at Hydrogen production plants<br>• Summary of scoping documents prepared for petroleum refineries<br>• Preliminary Concepts for PAR 1118<br>• Proposed updates to flare event notification system (FENS) |
| October 25, 2023 | Working Group Meeting #4 | • Presentation by representatives from Providence Photonics on remote sensing technologies<br>• Proposal to lower sulfur dioxide performance target<br>• Proposal to adjust mitigation fees<br>• Proposal for control of nitrogen oxides at Hydrogen production plants<br>• Proposal and cost-effectiveness analysis for potential control of flaring emissions at LPG flares |
| December 8, 2023 | | Released Initial Preliminary Draft Rule Language |
| December 12, 2023 | Working Group Meeting #5 | • Proposal for control of nitrogen oxides at Hydrogen production plants<br>• Rule language and structure changes overview |
| January 19, 2024 | | Released Preliminary Draft Rule Language and Preliminary Draft Staff Report |
| February 8, 2024 | | Public Workshop |
| February 16, 2024 | | Public Consulting Session |
| February 16, 2024 | | Stationary Source Committee |
| March 1, 2024 | | Set Hearing |
| March 5, 2024 | | Released Draft Rule Language and Draft Staff Report |
| April 5, 2024 | | Public Hearing |

# CHAPTER 2 : EVALUATION OF FLARING EQUIPMENT AND DATA

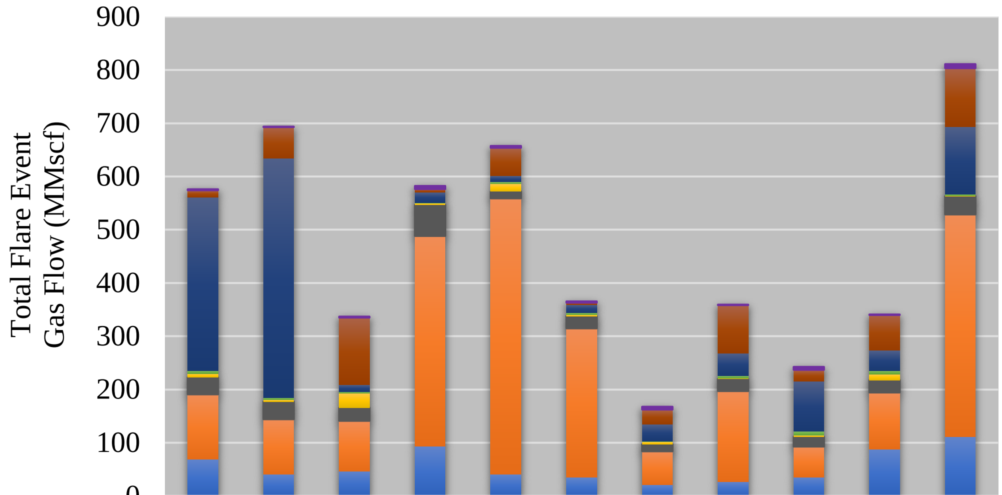
### *INTRODUCTION*

Flaring is a process that controls VOC by routing them to a remote, usually elevated, location where it is combusted in an open flame and open-air set-up using a specially designed burner tip. Flares operate as a safety mechanism and control device, but the process of flaring can also produce undesirable byproducts including SOx, NOx, PM, CO, smoke plumes, noise, and large visual flame. However, through proper design and operation these undesired byproducts can be minimized. The majority of refineries and hydrogen plants have flare systems designed to relieve and vent a large volume of gas during emergency process upsets. Many flare systems at refineries are operated in conjunction with a baseload gas recovery system referred to as FGR. These systems recover and compress the VOC by combining it with the refinery fuel gas system for use as fuel for process heaters, boilers, and gas turbines. FGR systems allows the flare system to be used as a backup to handle emergency release situations. Depending on the quantity and quality of the VOC stream that can be recovered by FGR, there can be an economic advantage to recover the VOC rather than combusting it in the flare system alone.

Depending on the flare's design and application, flares may be used to service one or several processing units to control small or large volume of vent gas during an emergency. Therefore, flares can be classified into two main categories: general service flares and clean service flares. General service flares are used to dispose of vent gas from routine operations such as startups and shutdowns, turnaround activities, purged gas streams, and emergency vent gas release from process units' upsets. A clean service flare is used to only burn natural gas, hydrogen, liquified petroleum gas (LPG), or other gases with a fix composition vented from a specific equipment; the vent gas contains little to no sulfur, and the quality of the vent gas is usually predictable regardless of flaring events. Clean service flares can further be subcategorized as either a hydrogen flare or non-hydrogen LPG (propane and butane) flare. As the names imply, hydrogen service flares are located at hydrogen production plants and LPG flares are located at the propane and butane storage areas of a refinery.

### *HISTORIC FLARING EMISSIONS DATA*

Facilities have been submitting quarterly reports to South Coast AQMD for more than a decade. Quarterly reports contain flare events details including date, duration, cause, level of emissions, etc. Staff compiled all flare events data reported by regulated facilities' owners and operators in quarterly reports (during 2012 to 2021) to analyze flare event frequency and magnitude. Historical vent gas flared, as reported by regulated facilities in their Rule 1118 in quarterly reports, excluding hydrogen production plants, is depicted in the figure below.




| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Altair Paramount | 2 | 1 | 2 | 6 | 3 | 2 | 5 | 1 | 5 | 1 | 7 |
| Chevron Products Co. | 13 | 59 | 126 | 6 | 53 | 4 | 28 | 90 | 22 | 66 | 110 |
| Marathon LAR Carson | 326 | 449 | 13 | 19 | 11 | 15 | 31 | 43 | 94 | 38 | 126 |
| Marathon LAR Wilmington | 5 | 4 | 2 | 2 | 4 | 4 | 2 | 4 | 8 | 6 | 3 |
| Marathon SRP | 0.0 | 0.1 | 0.1 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Phillips LAR Carson | 7 | 3 | 27 | 3 | 14 | 2 | 4 | 1 | 2 | 11 | 1 |
| Phillips LAR Wilmington | 32 | 33 | 25 | 58 | 13 | 23 | 13 | 23 | 19 | 23 | 34 |
| Torrance Refining Company | 122 | 103 | 94 | 395 | 518 | 280 | 63 | 170 | 57 | 107 | 418 |
| Valero/Ultramar | 69 | 41 | 47 | 93 | 41 | 35 | 21 | 27 | 36 | 88 | 111 |

**Figure 2-1. Total Flare Event Gas Flow by Facility (million standard cubic feet)**

The following figure plots annual flaring emissions as reported for regulated facilities in quarterly reports, excluding hydrogen production plants. Note that the increase in VOC emissions during the recent years partially reflects an increase in the VOC emission factor that was adopted in the 2017 amendment of Rule 1118.

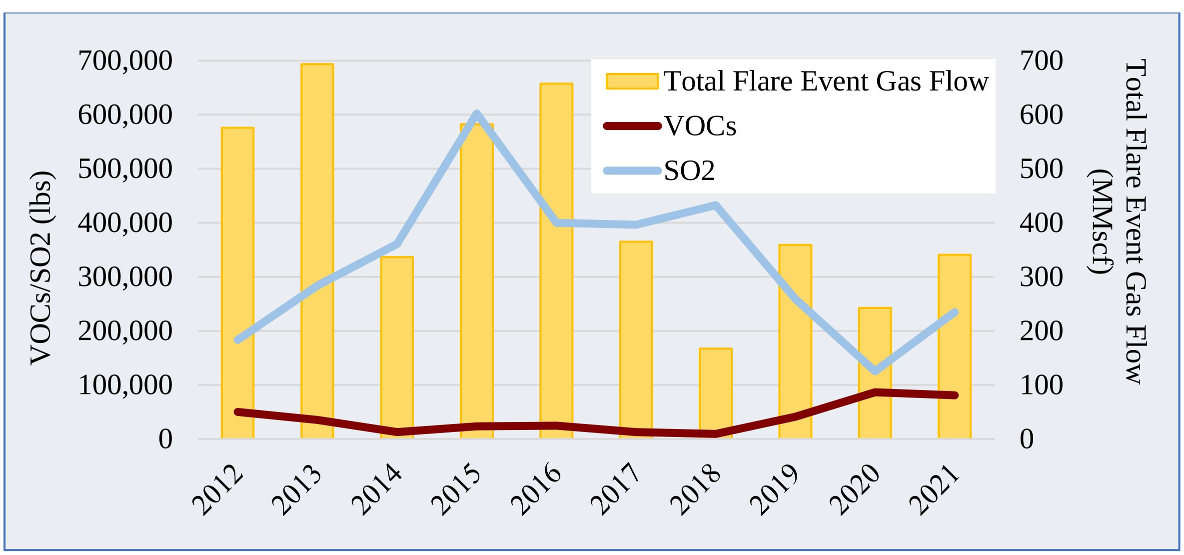



**Figure 2-2. Annual Flaring Emissions as Reported by Refineries in Quarterly Reports**

Facility owners and operators use 16 codes to classify the cause(s) of flare events in quarterly reports, as presented in the table below.

**Table 2-1. Categories for Relative Cause of Flare Events**

| Cause Codes | Description |
|---|---|
| Code 0 | Undetermined (use only if flow was more than 5,000 but smaller than or equal to 500,000 scf, and a cause analysis did not reveal a cause) |
| Code 1 | Turnaround Activity (Excluding planned maintenance and planned start-ups and shutdowns) |
| Code 2 | Planned Maintenance (Excluding turnarounds, and planned start-ups and shutdowns) |
| Code 3 | Emergency Flaring (includes any unplanned shutdown, subsequent start-up, valid breakdown, etc.) |
| Code 4 | Planned Start-up or Shutdown (Excluding planned maintenance and turnarounds) |
| Code 5 | EON - Relief Valve Leakage due to malfunction |
| Code 6 | Non-Emergency Flaring (For use only if no other code is the primary cause of the flare event) |
| Code 7 | Process Vent (i.e., facilities/units with no vapor recovery installed) – use only if flow was more than 5,000 but smaller than or equal to 500,000 scf |
| Code 8 | EON - Temporary Fuel Gas Imbalance |
| Code 9 | Code unassigned - Reserved for future use |
| Code 10 | Minor Vent (may only be used for vent gas flow less than 5,000 scf) |
| Code 11 | EON - Unrecoverable Stream |
| Code 12 | EON - Clean Service Stream |
| Code 13 | EON - Intermittent Minor Venting |
| Code 14 | EON - Pressure/Temperature Excursion |
| Code 15 | Purge Gas (i.e., refinery fuel gas, no flare gas recovery installed) |

Facilities report flare events in the quarterly reports using the cause codes. Staff evaluated flare events data in quarterly reports for frequency of flare events by code (2012 – 2021), as presented in the figure below. Results demonstrate that more than 80 percent of the events (i.e., counts) that occurred between 2012 and 2021 were either minor gas vent or clean service stream.

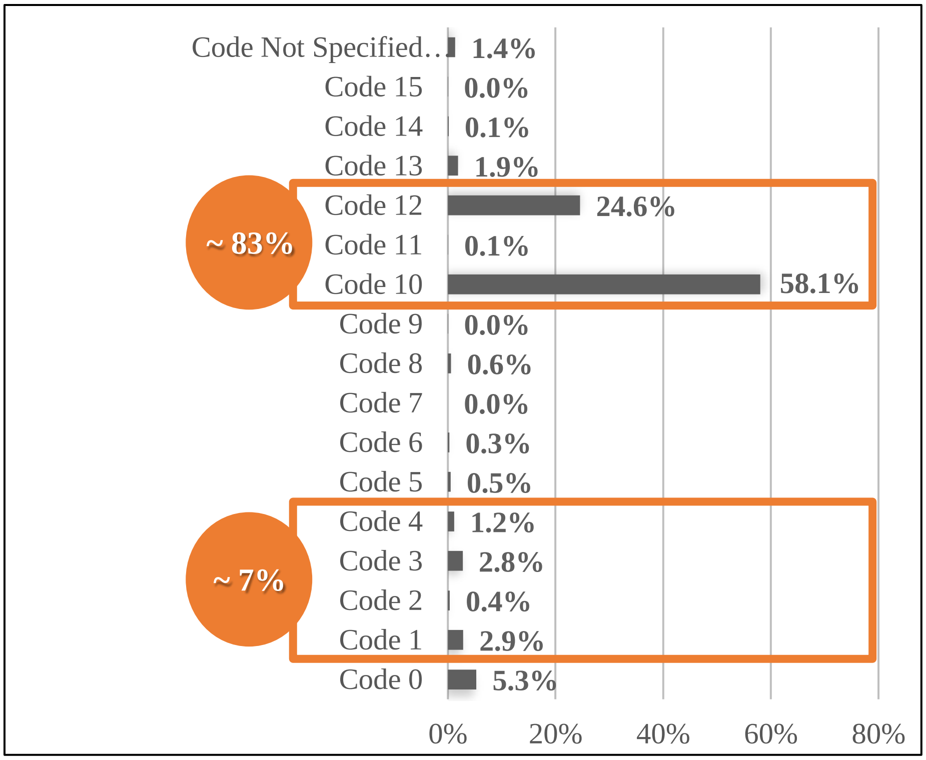



**Figure 2-3. Flare Events Frequency by Cause Code (2012 – 2021)**

Summary of reported data on the volume of flared vent gas for each regulated facility in quarterly reports is presented in the figure below. According to historic flaring data, reducing the frequency of flare events may not be the ultimate path towards reducing emissions from flaring. Data shows that seven percent of the flare events (by counts) caused more than 70 percent of total flared vent gas (2012 – 2021):

- Planned maintenance (Code 2) and planned startup/shutdowns (Code 4) generated about 27 percent of total flared vent gas.
- Emergency flaring (unplanned shutdown, subsequent start-up, valid breakdown, etc.) (Code 3) generated about 34 percent of total flared vent gas.

Reduction in flaring emissions is achievable by lowering frequency of flaring, including the frequency of flaring at clean service flares, as well as reducing the amount of vent gas being combusted at the flare through implementing operational improvements and conducting alternative practices to flaring.

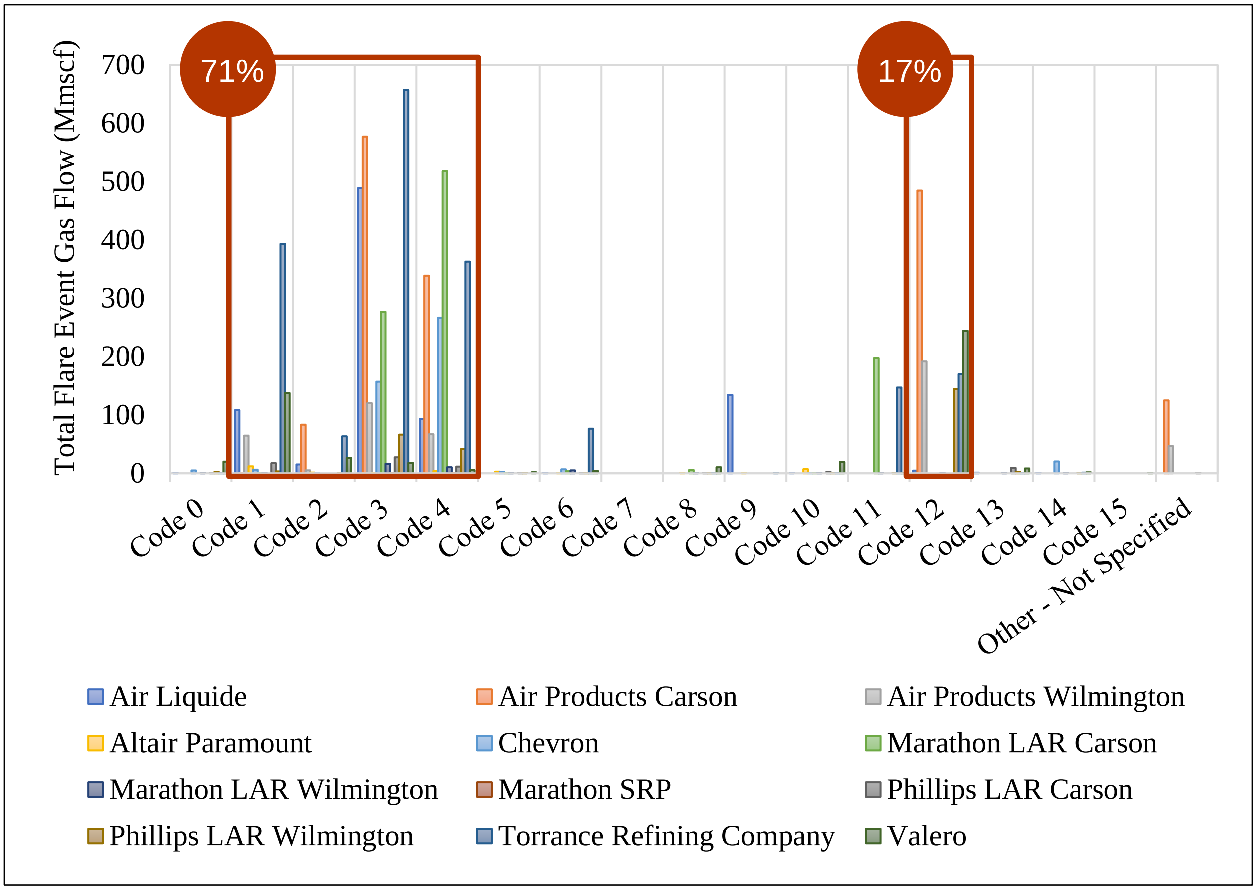


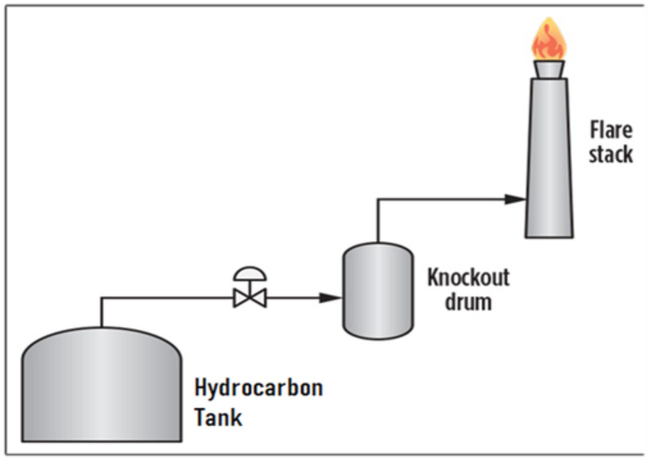

**Figure 2-4. Total Gas Flow of Flare Events by Cause Code and by Facility (2012 – 2021)**

*Clean Service Flares*

Clean service flare refers to a flare that is designed and configured by installation to combust only clean service streams, such as natural gas, hydrogen gas, liquefied petroleum gas, and/or other gases with a fixed composition that inherently have a low sulfur content. Quarterly reports indicate that "flaring clean service streams (Code 12)" as a significant cause for flaring. Over 10 years, flaring clean service streams was accounted for 25 percent of the flare events by counts and constituted 17 percent of the total flared vent gas. Flaring clean service streams solely at facilities other than hydrogen production plants accounts for eight percent of the flare events by counts and eight percent of the total flared vent gas.

**Non-Hydrogen Clean Service Flares**

Clean service flares at facilities other than hydrogen production plants are defined as "nonhydrogen clean service flares" and are operated to control the pressure of refinery product tanks that store either propane or butane, through combusting the off gas from the tanks. The figure below depicts the schematic configuration of a non-hydrogen clean service flare attached to an LPG tank. These flares are also referred to as LPG flares due to the location and type of vent gas that is being combusted.




(Image Courtesy: GAS PROCESSING & LNG)

**Figure 2-5. Non-Hydrogen Clean Service Flare at Refinery**

Three facilities operate a non-hydrogen clean service flare (one flare per each facility), with significant amounts of vent gas flaring occurring at two out of three of these flares. Vent gas flow from these two flares represents high proportion out of the total flared vent gas at each facility, as shown in the figure below.

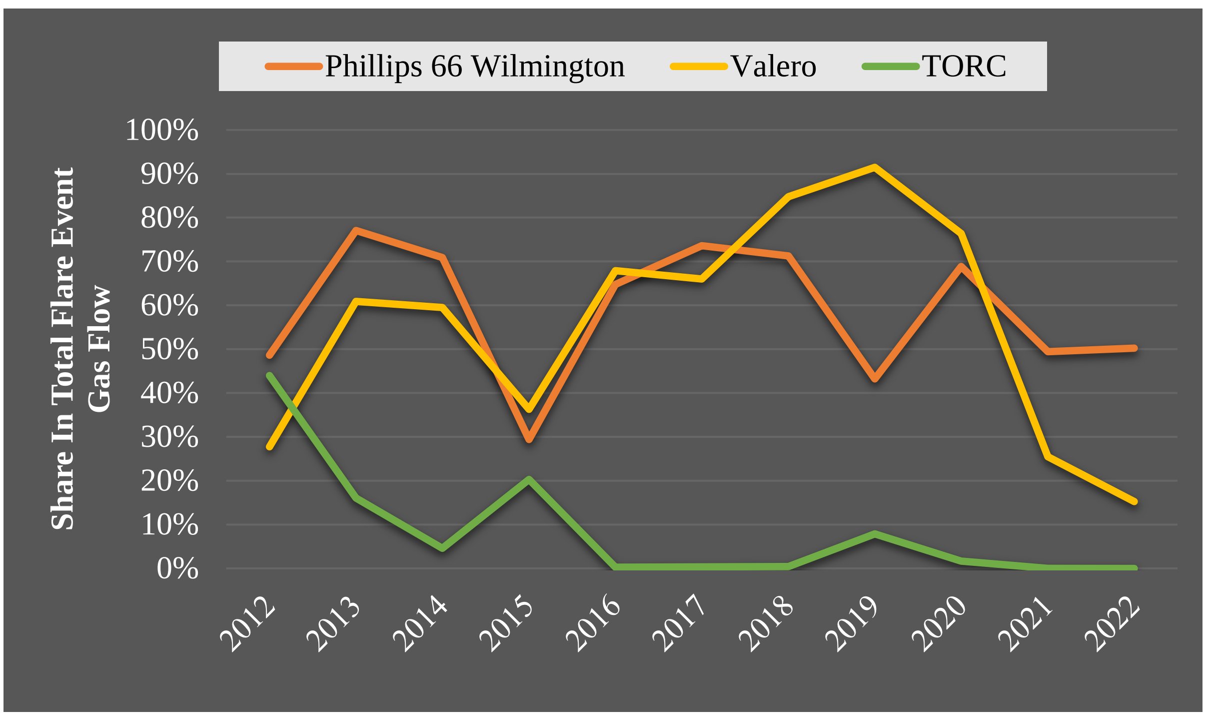



**Figure 2-6. Share of Flared Vent Gas Form Non-Hydrogen Clean Service Flare vs. Total Flared Vent Gas by Facility**

Clean service stream is a vent gas stream with inherently low sulfur content. Sulfur dioxides emissions are calculated using emission factors for each specific vent gas stream, e.g., propane, butane, natural gas, etc. However, facilities have the option to use an alternative method to calculate the emissions for non-hydrogen clean service flare using gas stream sampling. The alternative method is stated in the facility's approved Flare Monitoring and Recording Plan

(FMRP). Based on the data in quarterly reports, flaring at nonhydrogen clean service flares does produce sulfur dioxides emissions (see the figure below). In addition, flares are a source of oxides of nitrogen (NOx) emissions, which is the main pollutant responsible for the high ground level ozone concentrations in the South Coast AQMD.

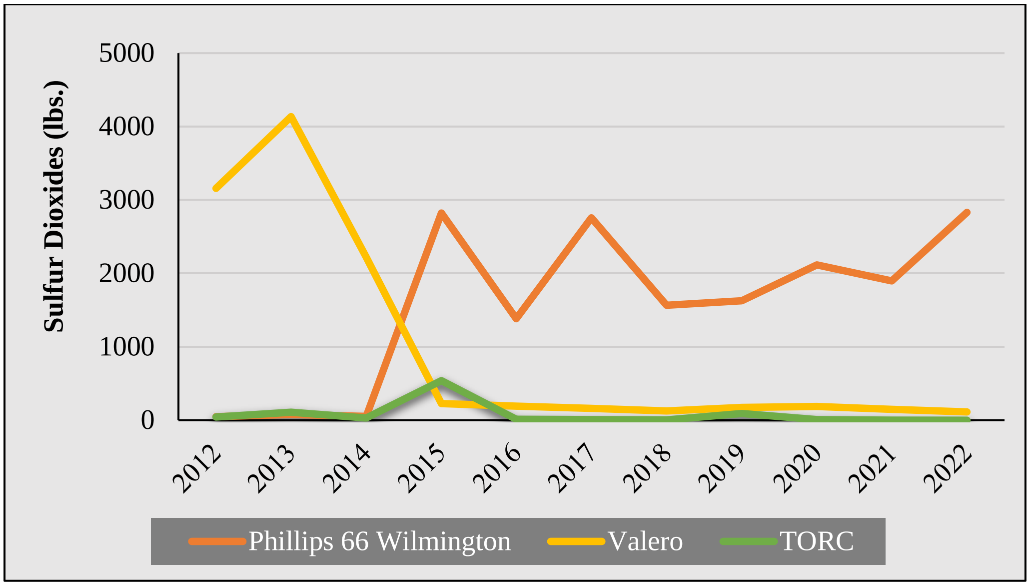



**Figure 2-7. Sulfur Dioxides Content from Clean Service Flares by Facility**

## Rule 1118.1 and Regulated Flares Located at Oil and Gas Production Facilities

Non-hydrogen clean service flares subject to Rule 1118 serve the same purpose as the flares located at tank terminals which are subject to Rule 1118.1, where the former rule seeks to control and minimize flaring and flare related emissions to reduce NOx and VOC emissions from flaring.

Rule 1118.1 – Control of Emissions from Non-Refinery Flares (Rule 1118.1) was adopted on January 4, 2019, to regulate NOx and VOC emissions from non-refinery flares located at landfills, wastewater treatment plants, oil and gas production facilities, organic liquid loading stations, and tank farms. Rule 1118.1 set specific capacity thresholds for each type of industry and Rule 1118.1 facilities are required to maintain their flare throughput below an annual capacity threshold (Rule 1118.1 Table 2). Any regulated flare under Rule 1118.1 that operates at a level greater than the specified capacity threshold for two consecutive years is required to implement at least one of the following actions:

- Reduce the level of flaring to below the capacity threshold (e.g., through beneficial use strategies)
- Replace the flare with a unit that complies with the lower NOx emissions limits.

Staff is proposing a similar approach for the non-hydrogen clean service flares regulated by Rule 1118 by establishing a throughput threshold. If a flare exceeds the threshold, the owner or operator would have to reduce the flare throughput.

### Hydrogen Clean Service Flares

Hydrogen production plant produces hydrogen from refinery fuel gas via steam methane reforming and pressure swing adsorption purification process. The produced hydrogen is supplied to refineries for use in various hydro-processing units. The purpose of flares at hydrogen production plants is to control emissions in the syngas (mainly a mixture of hydrogen and carbon monoxide) and pressure swing adsorption off-gas that is generated during abnormal plant operations, such as startup, shutdown, customer kick-back, and process upset conditions. The composition of streams to hydrogen clean service flares are lighter than those that would be vented at a refinery flare and mainly consists of hydrogen, methane, nitrogen, and carbon dioxide.

There are four hydrogen production plants regulated under Rule 1118 that provides hydrogen for local petroleum refineries via either a shared, medium-pressure product pipeline or direct high-pressure product pipelines. Rule 1118 hydrogen production plants operate two types of clean service flares:

- Enclosed/shrouded ground flare (Figure 2-8)
- Elevated flare (Figure 2-9)

Clean service flares located at hydrogen production plants are referred to as hydrogen clean service flares in this report. Hydrogen clean service flares use either nitrogen or natural gas as purge gas. Nitrogen does not combust, but natural gas combusts and generates NOx emissions.

(Image Courtesy: ZEECO®)

**Figure 2-8. Enclosed Ground Flare**

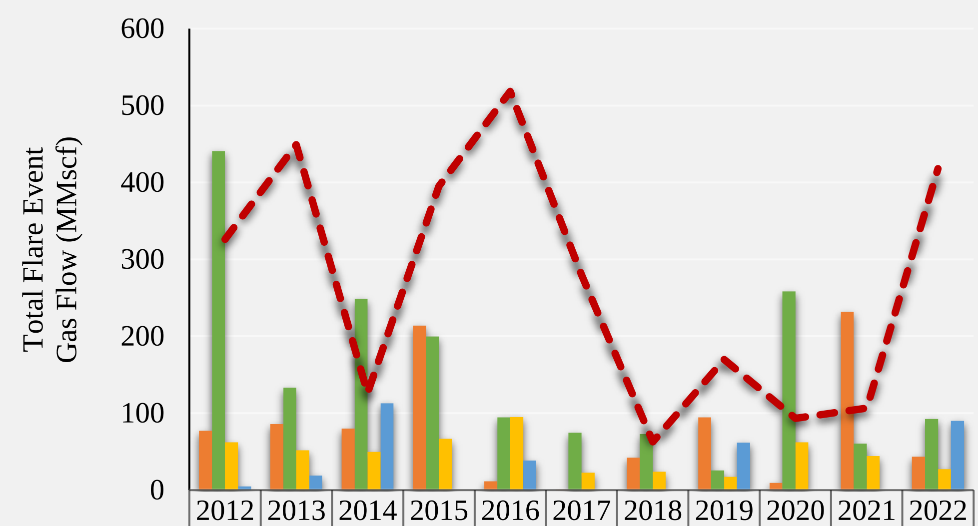
(Image Courtesy: Blackridge)

**Figure 2-9. Elevated Flare**

Three hydrogen production plants (Air Liquide, Air Products Wilmington, and Chevron) operate ground flares and one plant (Air Product Carson) operates an elevated flare. Air Products also operate two other hydrogen production plants located at Torrance Refinery site since 2022 which shares the refinery's general service flare system during any flare event that occurs at the hydrogen production plant. Staff excluded these two hydrogen production plants from evaluation of flaring emissions for hydrogen clean service flares. More information about these hydrogen production plants is provided later in this report.

In general, hydrogen production plants have flare events every day. Evaluation of flare event data reported in quarterly reports for hydrogen clean service flares shows that while most of these flare events were below the notification thresholds established in Rule 1118, about two percent of the flare events exceeded at least one of the established thresholds.

While the composition of vent gas stream to hydrogen clean service flares is mainly pure hydrogen, the annual amount of total vent gas flow to such flares is comparable in magnitude to the total annual amount of vent gas flow to the flare(s) at a petroleum refinery. The figure below presents an overview of total vent gas flow from Rule 1118 hydrogen clean service flares compared to total vent gas flow that flared at the refinery with the highest level of flaring vent gas in the corresponding year (i.e., maximum of all refineries).




| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Air Liquide | 77 | 86 | 80 | 214 | 11 | 0 | 42 | 95 | 10 | 232 | 43 |
| Air Products Carson | 441 | 133 | 249 | 200 | 94 | 75 | 73 | 25 | 258 | 60 | 92 |
| Air Products Wilmington | 62 | 52 | 50 | 67 | 95 | 23 | 24 | 17 | 62 | 44 | 27 |
| Chevron | 5 | 19 | 113 | 0 | 38 | 0 | 0 | 62 | 0 | 0 | 90 |
| Maximum of All Refineries | 326 | 449 | 126 | 395 | 518 | 280 | 63 | 170 | 94 | 107 | 418 |

**Figure 2-10. Total Flared Vent Gas from Hydrogen Clean Service Flares by Facility**

The level of sulfur content in the flare gas flow to hydrogen clean service flares is low. $SO_2$, if present, is the byproduct of combusting natural gas and refinery fuel gas as feedstock to pilots. The figure below shows the amount of $SO_2$ in the flared vent gas at the hydrogen clean service flares regulated by Rule 1118. This level of $SO_2$ is lower by a factor of 1,000 compared to the level of $SO_2$ in total flared vent gas at the refinery with the highest level of flaring vent gas in the corresponding year.

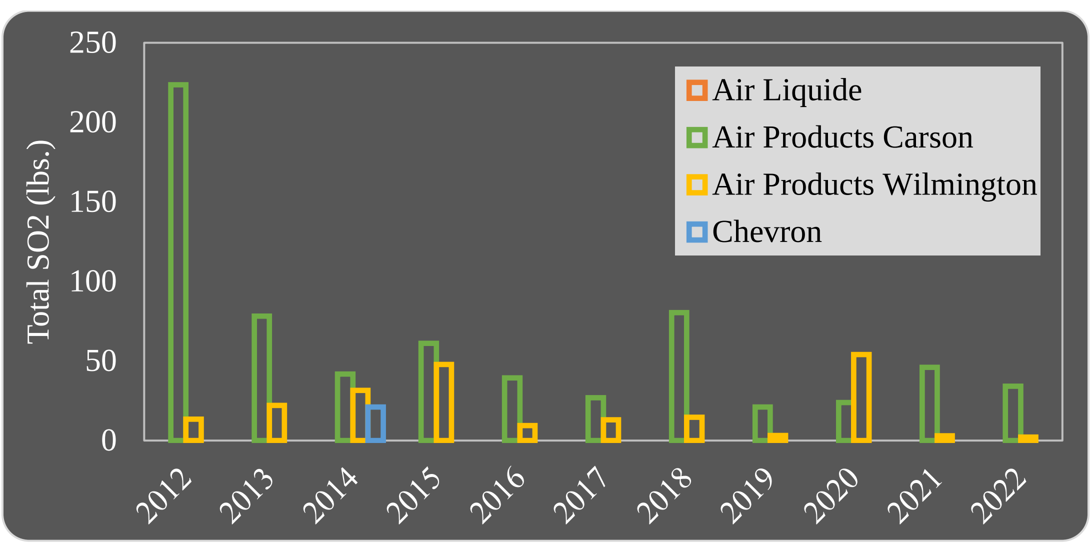



**Figure 2-11. Sulfur Dioxides from Hydrogen Clean Service Flares by Facility**

## Air Products Hydrogen Production Plants Located at Torrance Refinery

Air Products is currently operating two hydrogen production plants located at Torrance Refinery site. These hydrogen production plants were sold to Air Products in 2020 and Air Products took over the operation at hydrogen production plants in May 2022. The two hydrogen production plants are operated exclusively by Air Products, but the generated flare vent gas at these plants is directed to the Torrance Refinery's flare gas recovery system and general service flares.

Based on the current configurations, the vent gas streams from the refinery and hydrogen production plants are combined. The hydrogen production plants are connected to the refinery general service header and vent to the common flare header. The capacity of Torrance Refinery's flare gas recovery system may not be always sufficient to recover the high volumes of vent gas generated due to a flare event at the hydrogen production plants. As a result, the generated vent gas by hydrogen production plants causes flare events to occur at Torrance Refinery as well. Due to common header, when a flare event is initiated at the hydrogen production plants, refinery gas is also swept into the flare stream resulting in $SO_2$ emissions.

### *SPECIFIC CAUSE ANALYSIS REPORTS (SCARS)*

Rule 1118 requires the owners and operators of facilities to submit specific cause analysis reports (SCARs) identifying the cause of any flare event, excluding planned shutdown, planned startup, and turnarounds, when any of the following thresholds is exceeded: 100 pounds of VOC emissions, 500 pounds of sulfur dioxide emissions, or 500,000 standard cubic feet of vent gas is combusted. A SCAR is required to be prepared and submitted for a flare event that occurred during a planned shutdown, planned startup, or turnaround if it was as a result of a non-standard operating procedure. SCARs are expected to include the cause and duration of the flare event as well as any mitigation and corrective actions taken or to be taken to prevent the recurrence of a similar event.

Review of SCARs submitted to South Coast AQMD since 2009 shows that besides the aforementioned excluded causes, flare events have occurred as a result of equipment or instrument operational failure, equipment or instrument malfunction (physical damage), equipment tripping, piping failure (e.g., leakage), and loss of external or internal power sources.

Staff evaluated historical flare data to investigate the contribution of flare events associated with internal and external power loss to the total amount of flaring at facilities subject to Rule 1118. Flare events due to internal power loss are accountable for eight percent of flare events by count and flare events due to external power loss are accountable for five percent of flare events by count. Review of flare events data also shows that flaring due to external power loss has been more frequent in recent years (see the table below). This is an area where the owners and operators of facilities can take actions to reduce flare emissions below performance targets by upgrading electrical reliability at their facilities. For instance, one facility installed underground feeder lines at the cost of $75 million.

**Table 2-2. Flare Events due to External Power Loss**

| Year | Count of Flare Events Caused by External Power Loss |
|---|---|
| 2011 | 1 |
| 2012 | 1 |
| 2014 | 1 |
| 2016 | 3 |
| 2017 | 2 |
| 2018 | 1 |
| 2019 | 3 |
| 2021 | 6 |

The table below shows the share of flare events associated with internal power loss in the total amount of vent gas at different facilities. Many of the refineries have very low flare emissions caused by internal power loss though there is an opportunity for some to make improvements to reduce flare emissions through internal improvements.

**Table 2-3. Total Flared Gas due to Internal Power Loss (Percent of Total Vented Gas/year)**

| Year | Chevron | Marathon | P66 Wilmington | P66 Carson | Torrance | Valero |
|---|---|---|---|---|---|---|
| 2013 | - | - | 1% | - | - | - |
| 2014 | - | - | - | - | - | 5% |
| 2015 | 13% | - | - | - | - | - |
| 2016 | 16% | - | - | - | - | - |
| 2017 | 28% | - | 6% | 36% | - | - |
| 2018 | 52% | - | 0.01% | - | - | - |
| 2019 | - | - | - | - | - | - |
| 2020 | - | - | - | - | - | - |
| 2021 | 0.2% | 5% | - | 21% | - | - |

### *FLARE EVENT NOTIFICATION SYSTEM (FENS)*

FENS is a web-based notification system[2] for facilities to submit notifications as required by Rule 1118. An enhanced version of FENS was initially launched in 2019 which includes an interactive map, real time data, and historical flaring information. FENS was updated in 2020 to

[2] South Coast AQMD Flare Events Notification System, access at: https://xappprod.aqmd.gov/FENS/public

include new features, including wind speed and direction, list of recent events, etc. The figure below presents the FENS platform as accessible to the public.

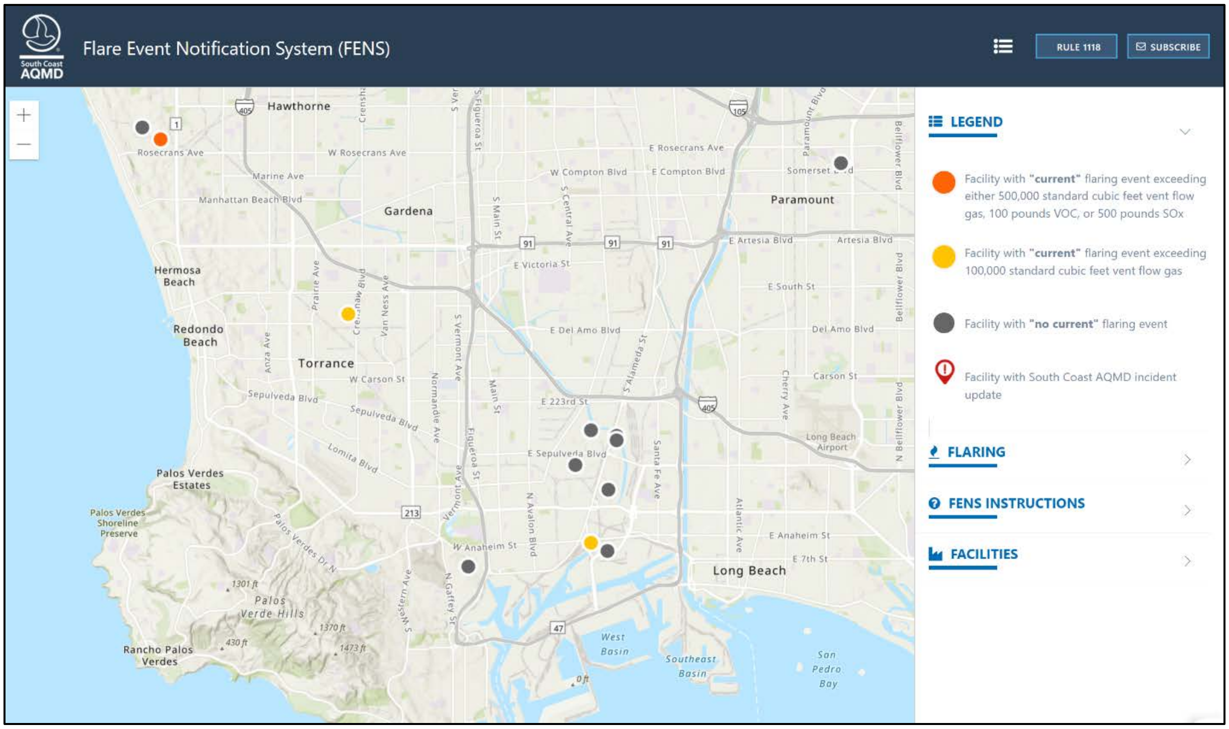



**Figure 2-12. FENS Public Platform**

The figure below shows the count of planned and unplanned flare events by year (2020 – 2023). This figure only includes the flare events that exceeded the established Rule 1118 thresholds, i.e., 500,000 standard cubic feet of total vent gas, 500 pounds of $SO_2$ emissions, and 100 pounds of VOC emissions. Other flare events are required to be reported by the facilities' owners or operators in the quarterly reports, but not in FENS. The figure below shows that the count of unplanned flare events that exceeded the established Rule 1118 thresholds have increased, while planned flare events that exceeded those thresholds have been constant in frequency during the same period of time.

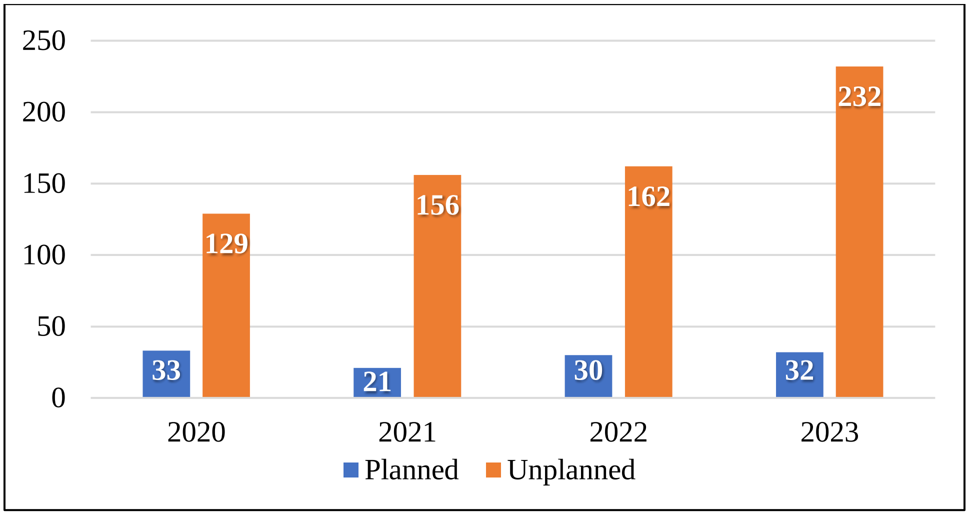



**Figure 2-13. Count of Flare Events Reported on FENS (Planned vs. Unplanned)**

Almost half of the flare events reported on FENS did not exceed the established Rule 1118 thresholds. These flare events are flare events, mainly unplanned (98 percent), that were required to be reported through FENS for exceeding the daily cumulative vent gas flow threshold of 100,000 standard cubic feet. The figure below shows the share of planned and unplanned flare events out of the flare events that exceeded at least one of the Rule 1118 thresholds.

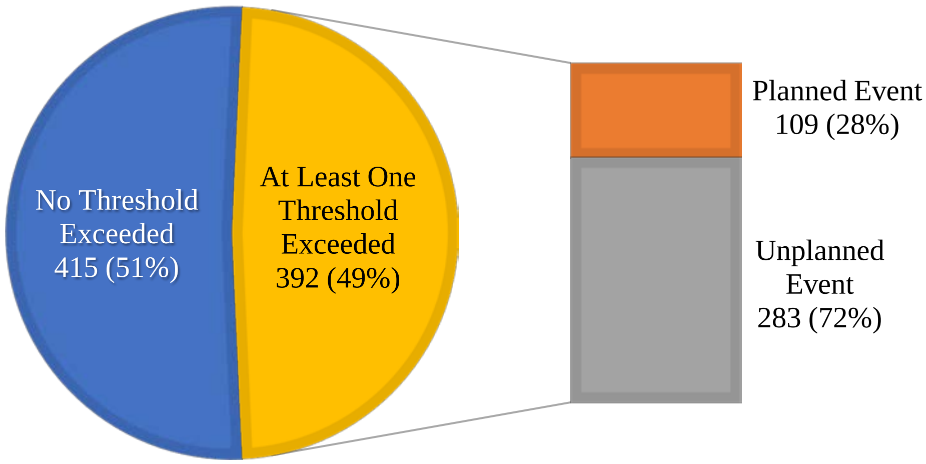



**Figure 2-14. Distribution of Flare Events by Type**

The figure below shows the count distribution of flare events (planned or unplanned) reported on FENS since 2020 that exceeded the established Rule 1118 thresholds. Different categories are not exclusive and there are flare events that exceeded more than one threshold for the entire flare event. Data shows an increase between 2020 and 2023 in the count of flare events that exceeded the threshold of “500,000 standard cubic feet of total vent gas”, but the count of flare events that exceeded the threshold of “500 pounds of $SO_2$ emissions” shows a decreasing trend.

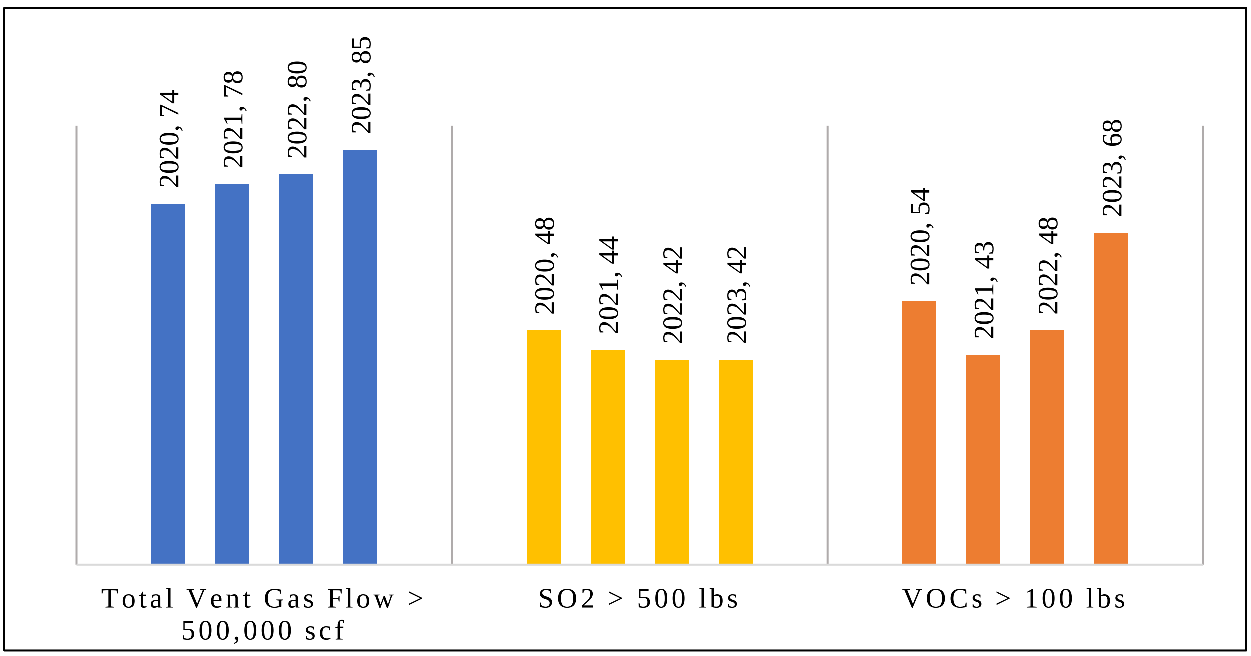



**Figure 2-15. Count Distribution of Reported Flare Events on FENS by Rule Thresholds**

### *Scoping Documents*

As part of 2017 amendments to Rule 1118, owners and operators of all facilities were required to submit a Scoping Document within 12 months of the rule amendment. Facility operators and owners were required to evaluate technical feasibility, approximate cost, and timing constraints to implement control options for minimizing or avoiding planned and unplanned flaring events. In addition, facility operators had to evaluate two potential alternatives for emission reductions from flaring during planned flare events at each of the following performance targets:

- 0.10 ton of $SO_2$ per million barrels of crude processing capacity
- 0.05 ton of $SO_2$ per million barrels of crude processing capacity
- 0.01 or less ton of $SO_2$ per million barrels of crude processing capacity
- 0.1 ton of VOC per year from clean service flares

Operators of facilities also had to evaluate emission reductions from flaring for four scenarios of unplanned flare event:

- Sudden influx of vent gas into the flare gas header
- Sudden loss of the process unit with the highest fuel gas consumption rate of recovered flare gas
- Sudden loss of all externally generated electrical power
- Sudden loss of internally generated electrical power

#### *Hydrogen Production Plants*

Operators of hydrogen production plants indicated the measures in scoping plans to reduce flaring, as listed in the following table.

**Table 2-4. Measures to Reduce Emissions from Flaring at Hydrogen Production Plants**

| Actions | Notes |
|---|---|
| Minimizing emergency flaring through eliminating the sources of plant tripping<br>• Addition or removal of specific instruments or equipment<br>• Proper operation/maintenance of specific instruments or equipment | One hydrogen production plant is implementing most of these actions already |
| Operate the plant with an uninterrupted power | |
| Limit the duration of planned shutdown event and planned startup event | |
| Use the hot restart operating procedure in the event of a plant shutdown following a process upset to temporarily maintain normal operating temperature in the heater when condition allows | |
| Installation of flare gas recovery system and gas turbine generator which would reduce planned and unplanned events<br>• Estimated capital cost: $50 million – $100 million<br>• Estimated operational cost: $20 million – $65 million per year (reflecting savings from reduced power demand) | Actions identified by the facilities as being costly or economically infeasible |
| Pressurize gases and place into on-site storage containers which may not be a feasible alternative due to safety concerns, physical plot space availability, and significant operational complexities<br>• Project implementation cost: $50 million – $100 million | |

*Facilities Other Than Hydrogen Production Plants*

Operators of facilities other than hydrogen production plants identified a number of actions in scoping documents to reduce planned and unplanned flaring and related emissions. Several of the listed actions are already being implemented at these facilities, such as training staff, managing flare gas, planning turnarounds, maintaining equipment, etc. Facility operators listed actions that could be most impactful to be very costly, e.g., flare gas recovery with gas turbine which was listed to cost between $50 million and $100 million.

The identified potential alternatives in the scoping documents for emission reductions from flaring during planned flare events occurring at facilities other than hydrogen production plants can be categorized into three main categories, as presented in the following table.

**Table 2-5. Measures to Reduce Emissions from Planned Flare Events at Facilities Other Than Hydrogen Production Plants**

| Actions | Notes |
|---|---|
| **Emission Monitoring Enhancements** | |
| Modify existing flare header flow meters to more accurately measure low molecular weight gas | Better to characterize and measure the flow gas, not for specific emission reductions. Staff is proposing to include additional requirement for flow meters. |
| Install new/additional flow meters | |
| New HHV analyzer for faster response time | |
| Modify flare water seal settings | |
| **Source Control Modifications** | |
| Develop planned turnarounds and perform critical maintenance during turnarounds | Refineries implementing most of these actions already |
| Capture lessons learned from flaring events with continuous improvement | |
| Operator training and developing a mindset for minimum flaring | |
| Evaluate root cause of all unplanned flaring events and propose corrective actions to minimize these events in the future | |
| Modify Operating Procedure for startup, shutdown, and clean service flare | |
| Use modified operating procedures and work practices to mitigate flaring | |
| Reduce plant feed rates which will reduce the amount of vent gas flared | Facilities could use this approach to reduce flare emissions below performance thresholds |
| **Tail End Control Enhancements** | |
| Modify reliability of flare gas recovery compressors | Refineries implementing most of these actions already |
| Keep spare equipment in optimal running condition | |
| Planning/managing the shutdown/startup activities to effectively manage the available vapor recovery capacity | |
| Use rental vapor/gas recovery equipment | Facilities could use these approaches to reduce flare emissions below performance thresholds |
| Use of temporary portable condensing system or sulfur scrubbing system | |

The table below includes the identified potential alternatives in the scoping documents for emission reductions from flaring during unplanned flare events occurring at facilities other than hydrogen production plants.

**Table 2-6. Control Measures to Reduce Emissions from Unplanned Flare Events at Facilities Other Than Hydrogen Production Plants**

| Actions | Notes |
|---|---|
| **A sudden influx of vent gas into a flare gas header** | |
| • Maximize operation of the Vapor Recovery System<br>• Use of spare Flare Gas Recovery equipment<br>• Improve reliability of process equipment | Refineries implementing most of these actions already |
| • Balance production and use of fuel gas at the refinery to minimize instances where excess fuel gas must be flared<br>• Automate the reduction of feed rate to the lower priority process units<br>• Reduce flaring by increasing fuel gas consumption to units within the plant<br>• Export excess fuel gas to third party to relieve pressure | Facilities could use these approaches to reduce flare emissions below performance thresholds |
| **A sudden loss of the process unit with the highest fuel gas consumption rate of recovered flare gas at that facility** | |
| • Maximize operation of the Vapor Recovery System<br>• Use of spare Flare Gas Recovery equipment<br>• Improve reliability of process equipment<br>• Automation of using spare equipment (if available) | Refineries implementing most of these actions already |
| • Balance production and use of fuel gas at the refinery to minimize instances where excess fuel gas must be flared<br>• Automate the reduction of feed rate to the lower priority process units<br>• Export excess fuel gas to a third party to relieve pressure | Facilities could use these approaches to reduce flare emissions below performance thresholds |
| **Loss of all external electrical power to the facility** | |
| • Operate Cogeneration Unit<br>• Install and use independent underground power feeders<br>• Reduce feed rates to lower priority process units<br>• Reduce power production of the cogeneration unit | Facilities could use these approaches to reduce flare emissions below performance thresholds |
| • Import electricity from a Third Party | Included in one refinery's scoping plan; already implemented |
| • Switch to Secondary External Feeder | |
| **A sudden loss of all electrical power from any non-backup electrical generation unit currently operating at the facility** | |
| • Import electricity from a Third Party<br>• Control mechanism to automatically receive power from local power supplier | Included in one refinery's scoping plan; already implemented |

Staff considered the information supplied in the scoping documents as well as staff's technical assessment during the rule development process. Chapter 3 details the proposed changes to Rule 1118 to reduce flare emissions.

# CHAPTER 3 : EMISSIONS CONTROLS ASSESSMENT

**PERFORMANCE TARGET ASSESSMENT**

**CONTROL OF EMISSIONS AT CLEAN SERVICE FLARES**

**PAR 1118 AND AB 617 CERP ACTIONS**

### *SULFUR DIOXIDE PERFORMANCE TARGET ASSESSMENT*

The $SO_2$ performance target was included in the 2005 amendment to Rule 1118. It required the owners and operators of petroleum refineries to comply with a declining annual $SO_2$ performance target. The $SO_2$ target was gradually reduced over a six-year period as shown in the table below. The current version of Rule 1118 includes a performance target for $SO_2$ emissions at 0.5 ton per million barrels (MMbbl) of crude processing capacity (over one calendar year). If the performance target is exceeded, the facility owner or operator is required to submit a flare minimization plan (FMP) and pay mitigation fees.

**Table 3-1. Gradually Decreasing Annual $SO_2$ Performance Target Since 2006**

| Facility | Crude Oil Capacity (2004) (Million Barrels) | Facility Specific $SO_2$ Performance Target (ton/yr) | | | |
|---|---|---|---|---|---|
| | | 2006 Target 1.5 tons/MMbbl | 2008 Target 1.0 ton/MMbbl | 2010 Target 0.7 ton/MMbbl | 2012 Target 0.5 ton/MMbbl |
| **AltAir Paramount** | 18.3 | 27.5 | 18.3 | 12.8 | 9.2 |
| **Chevron USA Inc.** | 95.2 | 142.7 | 95.2 | 66.6 | 47.6 |
| **Marathon Carson** | 95.2 | 142.7 | 95.2 | 66.6 | 47.6 |
| **Marathon Wilmington & SRP** | 36.1 | 54.1 | 36.1 | 25.2 | 18.0 |
| **Phillips 66** | 50.9 | 76.3 | 50.9 | 35.6 | 25.4 |
| **Torrance Refining Co.** | 54.7 | 82.1 | 54.7 | 38.3 | 27.4 |
| **Valero** | 29.6 | 44.4 | 29.6 | 20.7 | 14.8 |
| **Total** | **379.9** | **569.8** | **380.0** | **265.8** | **190.0** |

Mitigation fees are determined based on the percent of emissions in excess of facility-specific performance target, using the following equation:

$$
\begin{aligned}
&\mathit{Facility\ Specific\ Performance\ Target}\ [\mathit{Tons\ of\ SO_2}] \\
&\quad = \mathit{Performance\ Target}\ \left[\frac{\mathit{Tons\ of\ SO_2}}{\mathit{Million\ Barrels}}\right] \\
&\quad \times \mathit{Crude\ Processing\ Capacity}\ [\mathit{Million\ Barrels}]
\end{aligned}
$$

In the current version of Rule 1118, facility specific $SO_2$ performance target is calculated based on a facility's 2004 crude processing capacity. The list of facilities' processing capacity is publicly available on California Energy Commission's (CEC) website.[3] Processing capacity for most refineries has not changed since 2004, but two facilities have had operational changes:

[3] California Energy Commission – California's Oil Refineries Locations and Capacities: https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries

- AltAir (World Energy) transitioned from crude oil to alternative feedstocks and decreased capacity from 18.3 MMbbl/yr to 1.3 MMbbl/yr but plans to increase capacity in the coming years.
- Marathon integrated the operations of their Wilmington and Carson refineries.

Staff is proposing to lower the $SO_2$ performance target in two steps, to 0.35 ton per million barrels of processing capacity for the 2026 through 2028 calendar years and to 0.25 ton per million barrels of processing capacity for the 2029 calendar year and afterward. Staff extended the timeline from the preliminary draft rule to allow adequate time between the lowering of the target for the facilities to implement projects to reduce the flaring. Facility specific $SO_2$ performance targets are listed in the table below for each proposed phase. This proposed change will in part satisfy the AB 617 CERP requirement to achieve 50 percent reduction in flaring emissions in Rule 1118. Lowering the $SO_2$ performance target will result in more frequently submitted FMPs and additional mitigation fees paid by the owners or operators of facilities. Staff has documented decreases in facility flaring and flare emissions in the year following a year where a facility exceeds the performance threshold. Staff attributes this reduction to the facility evaluating their operations through the FMP and removal of the $4 MM cap for mitigation fees as part of the 2017 amendments. Removing the mitigation fee cap and adjusting mitigation fees annually utilizing the consumer price index going forward serves as a deterrent to flaring and incentivize facilities to minimize flaring emissions.

**Table 3-2. Proposed Gradually Decreasing Annual $SO_2$ Performance Target**

| Facility | Crude Oil Capacity (2023) (Million Barrels) | Facility Specific $SO_2$ Performance Target (ton/yr) | | |
|---|---|---|---|---|
| | | 2012 Target 0.5 ton/MMbbl | 2026 Proposed Target 0.35 ton/MMbbl | 2028 Proposed Target 0.25 ton/MMbbl |
| **AltAir Paramount** | 1.3 | 9.2 | 0.4 | 0.3 |
| **Chevron USA Inc.** | 98.2 | 47.6 | 34.4 | 24.5 |
| **Marathon Carson** | 98.3 | 47.6 | 46.5 | 33.2 |
| **Marathon Wilmington & SRP** | 34.6 | 18.0 | | |
| **Phillips 66** | 50.7 | 25.4 | 17.8 | 12.7 |
| **Torrance Refining Co.** | 55.1 | 27.4 | 19.3 | 13.8 |
| **Valero** | 31.0 | 14.8 | 10.9 | 7.8 |
| **Total** | **379.9** | **190.0** | **135.6** | **96.9** |

The level of $SO_2$ emissions per processing capacity is listed in the table below for all refineries regulated by PAR 1118. Staff used the data reported by the refineries in the submitted quarterly reports by each facility during the past decade in compliance with Rule 1118. Red cells in the table indicate the facility-years when the current $SO_2$ performance target of 0.5 ton per million barrels of processing capacity were exceeded. Yellow cells in the table indicate the facility-years when the current $SO_2$ performance target of 0.5 ton per million barrels of processing capacity was not exceeded, but the proposed $SO_2$ performance target of 0.25 ton per million barrels of processing capacity would be exceeded.

According to the table below, a $SO_2$ performance target of 0.25 ton per million barrels of processing capacity is achieved in practice at four out of seven crude oil processing refineries since 2017. Associated costs with reducing emissions are expected to be mainly due to the changes to the operational practices.

**Table 3-3. $SO_2$ Emissions per Processing Capacity by Refinery**

| Year | Chevron | Marathon Wilmington & SRP | Marathon Carson | AltAir Paramount | Valero | TORC | Phillips 66 |
|---|---|---|---|---|---|---|---|
| **2012** | 0.11 | 0.59 | 0.02 | 0.001 | 0.48 | 0.80 | 0.61 |
| **2013** | 0.29 | 0.07 | 0.06 | 0.000 | 0.21 | 0.40 | 0.31 |
| **2014** | 0.29 | 0.04 | 0.00 | 0.000 | 0.54 | 0.50 | 0.57 |
| **2015** | 0.23 | 0.01 | 0.03 | 0.003 | 0.13 | 1.90 | 0.91 |
| **2016** | 0.13 | 0.08 | 0.01 | 0.001 | 0.63 | 0.30 | 0.30 |
| **2017** | 0.00 | 0.17 | 0.02 | 0.001 | 0.15 | 0.70 | 0.30 |
| **2018** | 0.11 | 0.01 | 0.03 | 0.001 | 0.01 | 0.20 | 0.74 |
| **2019** | 0.07 | 0.43 | 0.02 | 0.000 | 0.01 | 0.20 | 0.47 |
| **2020** | 0.03 | 0.06 | 0.08 | 0.001 | 1.10 | 0.11 | 0.20 |
| **2021** | 0.16 | 0.64 | 0.06 | 0.001 | 0.51 | 0.10 | 1.02 |

The cost-effectiveness analysis completed for PAR 1118 did not include an analysis for the proposed $SO_2$ performance target of 0.25 ton per million barrel of processing capacity. Establishing a performance target is not the same as establishing BARCT emission limits and is different than imposing a control requirement. A performance target provides the facility with inherent flexibility to pursue the most cost-effective options available to that facility and does not require prescriptive controls that are able to be quantified. Therefore, a cost-effectiveness analysis is not required. Moreover, every facility is unique in their operation, arrangement, and physical layout, so analyzing the availability or cost-effectiveness of alternatives, and identifying a range of probable costs, is not applicable to a target established by means of a proposed performance standard. Facilities will likely work to stay below the performance target by implementing process or operational changes specific to each facility which cannot be quantified at this time.

According to the table above, two large petroleum refineries have been successful in performing below 0.5 ton of $SO_2$ per million barrel of processing capacity on a consistent basis. Staff evaluated the ability of these two facilities to consistently perform below the 0.5-ton target and explored the feasibility of reducing the $SO_2$ performance target from 0.5 to 0.1 ton per million barrels of processing capacity. Staff's evaluation concluded that the two facilities are equipped with physical controls or equipment capable of recovering and diverting the flare vent gas for use in a gas turbine cogeneration unit to produce electricity and steam. The equipment consists of a large flare gas recovery system, fuel gas treatment system, and multiple gas turbine/cogeneration units. Unlike the other facilities, these two facilities have the capability to absorb a sudden influx of vent gas into the flare header due to large flare gas recovery compressor system and reroute the excess flare vent gas to the gas turbine/cogeneration units. These gas turbine/cogeneration systems serve as a "sink" and provide the ability to absorb excess vent gas that would otherwise be sent to the flare for combustion. An additional advantage to this type of system for controlling flaring emissions is that it not only reduces $SO_2$ emissions, but concurrently reduces all flaring related emissions such as VOC and NOx. These units provide an option to beneficially use the excess flare gas that would otherwise be disposed of in the flare system.

Based on the information gathered, staff concludes that a large vapor recovery system and gas turbine/cogeneration system is potentially the most effective option in reducing overall flaring emissions to achieve the lower $SO_2$ performance target of 0.1 ton per day on a consistent basis. Since most of the flare vent gas will contain sulfur, a fuel gas treatment system will also be required to clean the gas prior to its combustion in the gas turbine/cogeneration system.

In order to assess the feasibility of implementing similar controls at other remaining facilities, staff gathered cost estimates for a gas turbine/cogeneration system, larger vapor recovery system, and fuel gas treatment system. Cost estimates were gathered from the scoping documents, vendor estimates, and confidential facility information surveys gathered from Rule 1109.1. Below are staff's assumptions:

- Gas Turbine (GTG)/Cogen System
  Maximum rated heat input was estimated using ratio of facility processing capacity. Heat input rating was then used to estimate natural gas fuel consumption.
- Vapor recovery upgrades or new larger compressor system
  Cost estimates were provided by facilities and vendors. Staff assumed necessary upgrades to flare gas recovery system would be similar for all facilities.
- Fuel gas treatment system to remove sulfur in the recovered flare vent gas
  Staff used the cost estimates received during Rule 1109.1 development through confidential fuel system survey from facilities and vendors.
- Installation cost, assumed to be 1.5 times the capital cost
  The installation cost includes engineering costs and Senate Bill 54 costs which requires refineries to hire unionized labor.
- Annual natural gas cost (as a recurring cost) due to variability of flaring
  Additional natural gas will be required to operate the GTG/Cogeneration system at a minimum baseload. These systems require several hours to reach steady operation, so must be kept running when a flaring event occurs the natural gas will be backed out and substituted with the recovered flare gas.
  - GTG/Cogeneration system gas consumption is estimated based on 25% operation at a cost of 54 cent per therm[4].
  - The GTG/Cogeneration system will require an SCR with additional costs for annual operation and maintenance (O&M) since ammonia and additional electricity will be required and adds annual O&M cost. Staff assumed an annual O&M cost of $250,000.
- The facility will be generating power and steam, and as a result, a cost savings will be realized since the facility will be importing less electricity. Staff assumed a savings of approximately $2 million per month ($24 million per year) and subtracted from annual O&M.

The table below lists the staff's cost estimate for each of the facilities that would need to install the new control equipment as described above.

[4] SoCal Gas – Natural Gas Prices: https://www.socalgas.com/for-your-business/energy-market-services/gas-prices

**Table 3-4. Estimated Costs for Gas Turbine/Cogeneration System, Larger Vapor Recovery System, and Fuel Gas Treatment System**

| Facility | GTG/Cogen Capital Cost ($) | Flare Gas Recovery System Upgrades ($) | Fuel Gas Sulfur Removal System ($) | Install cost ($) | Total Installed Cost ($) | Annual NG Cost ($) |
|---|---|---|---|---|---|---|
| **Refinery 1** | 33 MM | 30 MM | 62 MM | 50 MM | 175 MM | 20 MM |
| **Refinery 2** | 47 MM | 30 MM | 88 MM | 70 MM | 234 MM | 28 MM |
| **Refinery 3** | 62 MM | 30 MM | 117 MM | 93 MM | 302 MM | 37 MM |
| **Refinery 4** | 54 MM | 30 MM | 102 MM | 81 MM | 267 MM | 16 MM |
| **Refinery 5** | 54 MM | 30 MM | 102 MM | 81 MM | 267 MM | 16 MM |

For the cost-effectiveness calculation, staff assumed a 25-year useful life, a 4-percent interest, and baseline emission year of 2017. In addition, an assumption of 80 percent reduction was used since a reduction of $SO_2$ performance target from 0.5 to 0.1 ton per million barrels of processing capacity is approximately 80 percent. The table below summarizes staff's cost-effectiveness analysis for an 80 percent reduction $SO_2$.

**Table 3-5. Cost Estimates to Reduce $SO_2$ Performance Target From 0.5 to 0.1 (ton/MMbbl)**

| Pollutant | $SO_2$ |
|---|---|
| **Cost of Control (PWV)** | $2 Billion |
| **Estimated Emission Reductions (tpy)** | 1,281 |
| **C/E Threshold Per Ton** | $50,000 |
| **Cost-Effectiveness** | $1.6 MM |

Staff's analysis concluded it was not cost-effective to reduce $SO_2$ emissions from the current 0.5 to 0.1 ton per million barrels of processing capacity. Staff recommends a $SO_2$ performance target of 0.25 ton per million barrels of processing capacity. As mentioned previously, most facilities have proven that the 0.25 ton of $SO_2$ is achievable with operational practices and existing equipment. Most facilities will likely work to stay below the performance target of 0.25 ton per million barrels of processing capacity by implementing smaller scale projects and through process or operational changes specific to each facility.

### *Control of Emissions for Clean Service Flares and NOx Performance Target*

Clean service streams are low in level of sulfur content. In general, there are two categories of clean service flares regulated under PAR 1118:

- Hydrogen clean service flares
- Non-hydrogen clean service flares which include liquified petroleum gas (LPG) flares.

#### *Hydrogen Clean Service Flares*

Hydrogen clean service flares are control devices for the vent gas stream generated during normal and abnormal operations at hydrogen production plants and due to hydrogen kick-back by customer. Vent gas stream composition is primarily hydrogen, methane, nitrogen, and carbon dioxide.

Hydrogen clean service flares are subject to the Rule 1118 $SO_2$ performance target, but the vent gas streams to these flares have very low sulfur content. As a result, the requirements for an FMP submission and payment of mitigation fees have never been triggered for any of the hydrogen production plants; therefore, no flare minimization actions have been taken at hydrogen clean service flares to reduce $SO_2$ emissions.

All flares, including clean service flares, are a significant source of NOx emissions. NOx emissions are the most significant precursor of ground level ozone formation and the South Coast AQMD must reduce these emissions wherever feasible. South Coast AQMD previously adopted Rule 1118.1 in 2019 with the purpose to reduce flaring and flare emissions, specifically NOx emissions, from non-refinery flares.

For the hydrogen clean service flares subject to Rule 1118, NOx emissions have ranged from zero to 0.37 pounds per hydrogen production capacity (lbs/MMscf) over the last ten years and the emissions vary based on operational needs and unit maintenance. Staff proposes to establish an annual NOx performance target to control NOx emissions from hydrogen clean service flares. The proposed NOx performance target is 0.3 pound per million standard cubic feet (MMscf) of the facility's hydrogen production capacity.

The cost-effectiveness analysis completed for PAR 1118 did not include an analysis for the proposed NOx performance target. Establishing a performance target is not the same as establishing BARCT emission limits and is different than imposing a control requirement. A performance target provides the facility with inherent flexibility to pursue the most cost-effective options available to that facility and does not require prescriptive controls that are able to be quantified. Therefore, a cost-effectiveness analysis is not required. Moreover, every facility is unique in their operation, arrangement, and physical layout, so analyzing the availability or cost-effectiveness of alternatives, and identifying a range of probable costs, is not applicable to a target established by means of a proposed performance standard. Facilities will likely work to stay below the performance target by implementing process or operational changes specific to each facility which cannot be quantified at this time.

Hydrogen production plants will be subject to a NOx performance target of 0.3 pounds per MMscf of hydrogen production capacity since most of the facilities can achieve the proposed target with only operational changes. The facilities will be required to pay mitigation fees with the same schedule as the $SO_2$ performance target if the facility's specific NOx performance target is exceeded. The NOx performance target and mitigation fees will impact four hydrogen production facilities and is not a substitute for installation of direct controls.

In order to evaluate the potential cost of direct controls for hydrogen production plants and achieve a lower NOx performance target beyond the 0.3 pounds per MMscf, staff reviewed the scoping documents provided by the facilities and concluded that a gas turbine generator (GTG) system along with a flare gas recovery system is potentially the best alternative to significantly reduce NOx emissions associated with flaring at hydrogen clean service flares. The technology used to control flaring emissions at hydrogen plants is similar to the system used at the refineries except that a cogeneration system is not needed since the facility generates steam through its hydrogen production process. In addition, the facility will not need a fuel gas treatment system since the recovered flare gas is very low in sulfur. The GTG and flare recovery system can potentially reduce flaring by 90 percent and achieve a lower performance target of 0.03 tons per MMscf. Since most of the hydrogen production plants operate in a similar manner, staff assumed that a GTG and flare recovery system is also ideal for all four hydrogen production plants. The combination of flare gas recovery and GTG recovers the flare vent gas stream that would otherwise be sent to the flare to be used as fuel for the GTG cogeneration system. However, due to the composition variability and HHV content of the recovered gas stream, it is also necessary to add natural gas as supplemental fuel to operate GTG. Based on the facilities' assessments, the heat duty of the flared gas can be as high as 1,225 MMBtu per hour; to ensure stable operation, the new GTG system needs to continually process 4,900 MMBtu per hour of supplemental natural gas; therefore, the maximum firing rate has to be 6,125 MMBtu per hour. Facilities may need to install multiple GTG units; however, for the purposes of this analysis, staff assumed one large GTG unit would suffice. Below is a summary of the estimated cost-effectiveness for the installation of the GTG and flare gas recovery system to reduce NOx emissions from flaring by 90 percent.

**Table 3-6. Cost Estimates to Reduce NOx Emissions from Flaring at Hydrogen Plants**

| Pollutant | NOx |
|---|---|
| **Cost of Control (PWV)** | $760 Million |
| **Estimated Emission Reductions (tons)** | 50 |
| **C/E Threshold Per Ton of NOx** | $349,000 |
| **Cost-Effectiveness** | $15 Million |

Using the discounted cash flow method, a 25-year useful life, and a 4-percent interest, the cost-effectiveness of controls is calculated as $15 MM per ton of NOx reduced which is significantly more than the adjusted mitigation fees of up to $158,000 per ton of excess NOx that facilities would be required to pay if the NOx performance target were exceeded. Requiring the hydrogen production plants to pay a mitigation fee similar to the $SO_2$ performance target and adjusting the mitigation fees for exceeding the NOx performance target using CPI is a reasonable method because the equivalent cost of installing controls is significantly higher.

*Mitigation Fees*

Facilities that exceed $SO_2$ or NOx performance target must pay mitigation fees, determined based on the percent of emissions in excess of facility-specific performance target, according to the schedule in the table below.

**Table 3-7. Mitigation Fees for Exceeding $SO_2$ or NOx Performance Target**

| Excess Emissions (%) | Mitigation Fees ($/ton of Excess $SO_2$) |
|---|---|
| ≤10 | 25,000 |
| >10 to ≤20 | 50,000 |
| >20 | 100,000 |

All flare emissions, except for those caused by external power curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters, or acts of war or terrorism, are subject to this mitigation fee if a facility's $SO_2$ or NOx emissions exceed the $SO_2$ or NOx performance target, respectively. Rule 1118 current mitigation fees were established in, and have not changed since, 2004. The rule used to include an annual cap of $4 million; however, as part of the 2017 amendment to Rule 1118, the $4 million annual cap on mitigation fees was removed.

This mitigation fund can only be spent with authorization from the South Coast AQMD Governing Board. Historically, mitigation fees have been used for certain emission reduction incentive programs, such as port of Long Beach zero-emission and hybrid terminal equipment deployment and demonstration project, zero-emission, and clean energy demonstration projects, etc. Programs for spending these mitigation fees are developed outside of this rule amendment process.

Mitigation fees serve as an incentive for facilities to reduce overall annual flaring emissions and explore options to reduce flaring but are not a direct substitute for installation of emissions control equipment. The WCWLB community CERP objectives acknowledged that fees have not changed since 2004. In alignment with the WCWLB community CERP objectives, staff is proposing to adjust the mitigation fees calculation based on Consumer Price Index (CPI) moving forward; this will ensure that mitigation fees are representative of the year in which they are paid if an exceedance of the facility's specific performance target were to occur. Using CPI is a reasonable method for fee adjustment and is significantly less costly than equivalent reductions through the installation of controls.

**$SO_2$ Mitigation Fee Increase Discussion**

As previously discussed, beneficial use of the recovered flare vent gas to generate electricity and steam is the most effective option in reducing overall flaring events and associated emissions according to staff's research. The control technology evaluated at the refineries was a gas turbine/cogeneration system and can potentially reduce $SO_2$ emissions (by at least 80 percent). Staff's cost estimate for controls using a gas turbine/cogeneration system and all associated equipment is approximately $1.2 billion with an associated estimated reduction of 1025 tons of $SO_2$ over the course of 25 years. According to Table 3-5, the associated costs of such system equate to approximately $1.2 million per ton of $SO_2$ reduced, whereas an exceedance of a facility's specific performance target would require the facility to pay the adjusted mitigation fee of up to $158,000 per ton of excess $SO_2$ and the relatively lower costs of taking corrective actions (to include process or operational changes) to reduce flare emissions. Thus, adjusting the mitigation fees for exceeding the $SO_2$ performance target using CPI results in significantly lower costs than the equivalent cost of installing controls. ~~Similarly, hydrogen production plants will be subject to a NOx performance target of 0.3 ton per hydrogen production capacity (MMscf) and will be required to pay a similar mitigation fee amount if the facility's specific NOx performance target is exceeded. The NOx performance target and mitigation fees will impact four hydrogen production facilities and is also not a substitute for installation of direct controls.~~

**NOx Mitigation Fee Discussion**

Beneficial use of the recovered vent gas to generate electricity is the most effective option in reducing overall flare events and associated emissions at hydrogen production plants. The control technology evaluated at the hydrogen production plants was a gas turbine generator and flare gas recovery system which can potentially reduce NOx emissions by at least 90 percent. Staff's cost estimate for controls using a gas turbine and flare gas recovery system is approximately $760 million with an associated estimated reduction of 50 tons of NOx over the course of 25 years. The associated costs of such a system equates to approximately $15 million per ton of NOx reduced, whereas an exceedance of a facility's specific performance target would require the facility to pay the adjusted mitigation fee of up to $158,000 per ton of excess NOx and the relatively lower costs of taking corrective actions (to include process or operational changes) to reduce flare emissions. Thus, adjusting the mitigation fees for exceeding the NOx performance target using CPI results in significantly lower costs than the equivalent cost of installing controls.

**Cost Estimates for Continuous Flow Meter**

Hydrogen production plants will be subject to a new NOx performance target of 0.3 pound per hydrogen production capacity (MMscf) which will require accurate measurements of the vent gas stream using a continuous flow meter. Most of the hydrogen production plants do not use a traditional flow meter to measure vent gas flow to the flare. The commonly used flow meters are designed to be completely open or completely closed ("on/off" flow meter) and the flow rates are calculated using equations developed from flow capacity curves provided by the flare manufacturer. Based on feedback from a hydrogen production plant, staff estimates the cost to replace an "on/off" flow meter with a continuous flow meter is approximately $400,000. When compared to the commonly used "on/off" flow meters, the new continuous flow meters will not have any additional operating and maintenance cost.

*Non-Hydrogen Clean Service Flares (LPG Flares)*

LPG flares are categorized as non-hydrogen clean service flares and are dedicated to the LPG storage or loading areas of refinery. These flares serve as control devices to control LPG vapors and large emergency release of LPG vent gas streams. LPG flares primarily combust vent gas from LPG storage tanks which is mainly composed of propane and/or butane. Non-hydrogen clean service flares regulated under PAR 1118 are located at three refineries in storage areas (tank terminals) and the majority of them are not integrated with refinery vapor recovery system. Flaring at LPG flares occurs when LPG vapor is relieved from pressure control valves or pressure safety valves (PSV) of storage tanks/vessels, when the LPG tanks/vessels are being de-inventoried for cleaning or inspection, and during turnaround maintenance.

**Figure 3-1. Non-Hydrogen Clean Service Flare (LPG Flare)**

Recovering LPG from non-hydrogen clean service flares is technically feasible and cost-effective. Two out of three refineries regulated by PAR 1118 have large amounts of flaring due to the continuous venting of gas streams from LPG tanks to non-hydrogen clean service flares. The flaring from the non-hydrogen clean service flares may account for a majority of vent gas flow rate of total refinery flaring (historically as high as 90 percent per facility in a single year). One refinery uses a refrigeration/chiller system to minimize flaring of LPG vent gas streams. This system reduces, but does not eliminate, LPG flaring, as flaring still occurs during LPG tank clean-up and emergency release situations. The table below lists three Rule 1118 facilities that operate LPG clean service flares and the annually recorded throughput based on total gas flow for each flare (2017 to 2021).

**Table 3-8. Annual Throughput (MMBtu/year) for Non-Hydrogen Clean Service Flares**

| Year | Phillips 66 | Torrance | Valero |
|---|---|---|---|
| 2017 | 58,627 | 2,200 | 80,656 |
| 2018 | 33,307 | 488 | 62,820 |
| 2019 | 34,600 | 13,140 | 86,730 |
| 2020 | 45,013 | 981 | 95,244 |
| 2021 | 40,400 | 225 | 78,411 |

Non-hydrogen clean service flares are similar to certain type of flares subject to Rule 1118.1 (i.e., flares located at tank terminals). Rule 1118.1 regulates NOx and VOC emissions from non-refinery flares located at landfills, wastewater treatment plants, oil and gas production facilities, organic liquid loading stations, and tank terminals. Flares regulated by Rule 1118.1 that operate at greater than a specified capacity threshold are required to, either reduce the level of flaring to below the capacity threshold (e.g., through beneficial use strategies), or replace the flare with a unit complying with the lower NOx emission limits (ultra-low NOx flares).

Vent gas streams to LPG flares are low in sulfur, but combustion of such gas stream generates NOx emissions. Staff proposed a similar approach to Rule 1118.1 to establish a throughput threshold to minimize flaring from LPG flares. Reducing flare throughput reduces NOx emissions; however, directing vent gas streams from LPG tanks to the refinery vapor recovery system is challenging and costly, because the LPG tank is located far from the refinery vapor recovery system. That option was assessed by a refinery in their scoping plans but was eliminated as an infeasible option due to the high costs. The feasible option is to recover the LPG stream and recycle it back to the LPG storage tank itself. Also, LPG is a valuable commodity that can be recovered and sold rather than being combusted in a flare, which will result in some cost savings.

Staff calculated a throughput threshold with total heat content (based on higher heating value) in MMBtu per year where installing an auxiliary gas refrigeration/compression system becomes cost-effective. This throughput threshold can be used to trigger facilities to take actions to reduce faring emissions at non-hydrogen clean service flares. That assessment is detailed below.

### Technology Assessment

Staff’s evaluation concluded that a refrigeration/chiller system is the most effective technology to minimize or eliminate the continuous flaring occurring at the existing LPG flares. The technology is proven and achieved in practice since one refinery that is currently subject to the rule has already implemented and operates a refrigeration/chiller system which effectively recovers nearly all the LPG that would otherwise be burned at the flare. The auxiliary refrigeration/chiller system used for recovery of vent gas streams from LPG tanks and control of emissions from LPG flares is comprised of:

- Major equipment
- Compressor with motor and drive package
- Condenser
- Structural base
- Piping
- Insulation
- Control system
- Electrical conduit and upgrades
- Engineering and design
- Installation

The refrigeration/chiller system requires additional electricity to operate primarily due to the electrical demand of the compressor, which adds to the operating cost. However, butane/propane is a valuable commodity for the refinery and the recovered gas can be sold and generate additional revenue and offset the cost of the required energy. The generated profit is estimated to be approximately $190,000 per year.

One facility indicated that they may elect to replace their existing LPG flare system with a newer design in order to reduce or eliminate the amount of LPG continually being vented. The facility indicated that the system is equipped with a single totalizing flow meter and a majority of the gas combusted is attributed to the purge gas and not vent gas. The decision to potentially replace the LPG flare is due to the existing design of the current LPG flare system which requires a large purge flow rate to maintain the velocity/positive pressure, which is essential to prevent air intrusion into the system. A new flare system may consist of:

- Elevated flare – self supported 100 feet overall height rated for 500,000 pounds per hour (lb/hr) with carbon steel stack and utility tips and pilots
- Ignition system with automatic relight, pilot status monitors, sun/rain shield
- Utility piping/wire for pilot gas, ignition lines, conduit, thermal couple wire
- Corrosion protection with epoxy paint finish
- Structural base
- Engineering and design
- Installation

Unlike the chiller/refrigeration option, the new flare will not result in additional annual operating costs since a refrigerant compressor system is not necessary. However, the facility can generate additional revenue since the LPG can be sold rather than burned as waste. The estimated generated profit is approximately $392,000 per year.

**Cost-Effectiveness Analysis**

South Coast AQMD routinely conducts cost-effectiveness analyses regarding proposed rules and regulations that result in the reduction of criteria pollutants (NOx, SOx, VOC, PM, and CO). The analysis is used as a measure of effectiveness of the proposed control technologies and to measure the relative cost of more stringent controls. It is generally used to compare and rank rules, control measures, or alternative means of emissions control relating to the cost of purchasing, installing, and operating control equipment to achieve the projected emission reductions. The major components of the cost-effectiveness analysis are capital and installation costs, operating and maintenance costs, emission reductions, discount rate, and equipment life. The cost-effectiveness analysis for PAR 1118 was completed for each proposed amendment (except for the proposed $SO_2$ and NOx performance targets) using the discounted cash flow method explained below.

## Discounted Cash Flow (DCF)

The DCF method converts all costs, including initial capital investments and costs expected to be incurred in the present and all future years of equipment life, to present value. Conceptually, it is as if calculating the number of funds that would be needed at the beginning of the initial year to finance the initial capital investments and to be set aside to pay off the annual costs as they occur in the future. The fund that is set aside is assumed to be invested and generates a rate of return at the discount rate chosen. The final cost-effective measure is derived by dividing the present value of total costs by the total emissions reduced over the equipment life. The equation below is used for calculating cost-effectiveness with DCF. The equation was presented in the 2016 AQMP Socioeconomic Report Appendix 2-B (p. 2-B-3).

$$\text{Cost} - \text{Effectiveness} = \frac{\text{Initial Capital Investments} + (\text{Annual O\&M Costs} \times \text{PVF})}{\text{Annual Emission Reductions} \times \text{Years of Equipment Life}}$$

Where:

$$\text{PVF} = \frac{(1+\text{r})^{\text{N}} - 1}{\text{r} \times (1+\text{r})^{\text{N}}}$$

Where:

r = real interest rate (discount rate)
N = years of equipment life

## Cost-Effectiveness Screening Threshold

The South Coast AQMD Governing Board adopted the 2022 AQMP on December 2, 2022, which establishes a new cost-effectiveness screening threshold of $325,000 per ton of NOx reduced. The new threshold utilizes a health-based approach and uses a public health monetized benefit value for reducing pollution. This is a similar approach to the one used by CARB and U.S. EPA where the associated costs with a rule are compared to the monetized benefits associated with the resulting emission reductions. The $325,000 threshold was based on U.S. EPA established monetized benefit value of $307,636 and 2016 AQMP monetized benefit value of $342,000 per ton of NOx reduced. The 2022 AQMP states that the benefits-based screening threshold of $325,000 would be inflated through time to the dollar-year used in the control measure-specific socioeconomic analysis. The screening threshold will be inflated using the annual California Consumer Price Index (CPI) for consistency with how the benefits-based threshold was inflated to 2021-dollars in the 2022 AQMP and 2022 AQMP ~~s~~Socioeconomic ~~r~~Report. Using CPI is more appropriate than using the Marshall & Swift Index, because the screening threshold is health-benefits based. The inflation-adjusted screening threshold is not conducted for every rulemaking but rather annually based on the year the costs are brought into analysis. In the case of PAR 1118, the cost used in the assessment was based on 2022-dollars and the health-based screening threshold of $325,000 was based on 2021-dollars. The screening cost-effectiveness threshold was adjusted from 2021-dollars to 2022-dollar year using the CPI for 2022 and 2021, as stated below.

$$\text{Inflation Adjusted Threshold in 2022} = \text{Threshold in 2021} \times \left(\frac{\text{CPI in 2022}}{\text{CPI in 2021}}\right)$$
$$= \$325{,}000 \times \left(\frac{319.224}{297.371}\right)$$
$$= \$349{,}000$$

The adjusted cost-effectiveness screening threshold in 2022-dollars is $349,000 per ton of NOx reduce which is $24,000 higher than the $325,000 threshold in the 2022 AQMP.

## Summary of Cost Data and Assumptions

To determine cost-effectiveness for the proposed throughput threshold for non-hydrogen clean service flares, cost information and estimates for the control equipment were obtained. Staff gathered cost data and estimates for refrigeration compressor system, piping, instrumentation, structural steel, electrical upgrade, and engineering design. In addition, staff reached out to the affected facilities to gather equipment data and cost information for potential NOx control projects. One facility provided staff with project scope estimates that was conducted in 2019 by an engineering firm. Also, staff used a 25-year equipment life in calculating the cost-effectiveness of the control option.

Butane/Propane is a valuable commodity that can be recovered rather than disposing in flare and the generated revenue can be contributed to offset cost of regulatory compliance. Staff estimated the revenue from the recovery and sale of butane/propane to be realized up to approximately $392,000 per year (assuming 0.71 cents per gallon[5] for recovered propane at 65,000 standard cubic feet per day).

Compressor for refrigeration unit also requires additional electricity and staff assumed the industrial electricity rate of 0.18 cents per kilowatt-hour[6] to calculate the cost of required electricity.

### *Cost Estimates for The Auxiliary Gas Refrigeration/Compression System*

Cost estimates for the auxiliary gas refrigeration/chiller system were provided from vendors and facilities. Vendor cost estimates included compressor (150 hp) and condenser costs. Facility-provided cost estimates included the cost to send the recovered LPG gas to the vapor recovery system and process units. Staff incorporated the cost for piping, structural base, control system, instrumentation, panels, fireproofing, and insulation based on the cost estimates provided by the facility; these costs were incorporated into the cost evaluation as part of major equipment costs. For installation cost, staff assumed the cost to be equivalent to the capital/major equipment costs, however staff also included an additional 20 percent to the installation costs due to Senate Bill 54 which requires refineries to hire unionized labor. Staff adjusted cost estimates provided by the

[5] U.S. Energy Information Administration –EIA –Independent Statistics and Analysis, Sources and Uses, Petroleum and Other Liquids, Data, Prices – Daily Spot Prices, Propane – Mount Belvieu, Texas – 1992-2024, , propane price accessed on September 27, 2023. https://www.eia.gov/dnav/pet/hist/EER_EPLLPA_PF4_Y44MB_DPGD.htm

[6] California Energy Commission, 2022 Integrated Energy Policy Update, Docket 22-IEPR-03 – Electricity Forecast, CEDU Baseline Forecast – LADWP, accessed February 27, 2024: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248381&DocumentContentId=82804

facility using CPI for 2023-dollar year and calculated the total installed equipment cost of approximately $11.2 MM:

- Major equipment costs: $2.6 MM
- Electrical upgrades: $2.2 MM
- Installation costs: $3.2 MM (1.2x major equipment costs)
- Engineering costs: $3.2 MM

***Annual O&M Costs***

- Annual electricity costs: ~$176,000

***LPG Recovery Revenue***

- Butane/Propane revenue: ~$392,000

***Annual and Lifetime Cost Savings***

- Annual cost savings: ~$216,000
- Lifetime cost savings: ~$5.3 MM

***Cost Estimates for New LPG Flare***

Vendors provided a budgetary quote for a new elevated flare, self-supported 100 feet overall height, rated for 500,000 pounds per hour (lb/hr), and with a carbon steel stack. The flare cost also includes utility tips, pilot, ignition system with automatic relight, pilot status monitors, sun/rain shield, utility piping/wire for pilot gas, ignition lines, conduit, and thermal couple wire. Since the flare is elevated, staff also considered the cost of a structural base and foundation to withstand seismic activity. Staff incorporated the cost of piping and additional instrumentation based on facility provided estimate. For installation cost, staff assumed the cost to be equivalent to the capital/major equipment costs plus an additional 20 percent to account for Senate Bill 54 which requires refineries to hire unionized labor. The estimated total installed cost for a new LPG flare is approximately $10 MM

- Major equipment costs: $3.2 MM
- Installation costs: $3.8 MM (1.2x major equipment costs)
- Engineering costs: $3.0 MM

***Annual O&M Costs***

- No additional O&M Costs: $0

***LPG Recovery Revenue***

- Butane/Propane revenue: ~$392,000

***Annual and Lifetime Cost Savings***

- Annual cost savings: ~$392,000
- Lifetime cost savings: ~$9.8 MM

## Cost-Effectiveness Calculations

To calculate the cost-effectiveness, staff excluded the facility with an existing LPG recovery system in place. For the remaining two facilities, staff assumed one facility will install a refrigeration/chiller system and the other facility will install a new LPG flare. Cost-effectiveness calculations accounted for NOx emissions reductions only, but there will be additional co-benefits of reduced VOC and PM emissions. NOx emissions are calculated using the NOx emission factor as listed in PAR 1118 and as a result, the larger the LPG vent gas volume the higher NOx emissions. Staff used NOx emissions data averaged over a five-year period (2017 to 2021) as a baseline to account for operational variation in NOx emissions year-to-year and assumed a 90 percent reduction of flaring NOx emissions to be realized through the auxiliary gas refrigeration/compression system.

Staff calculated the minimum annual throughput at which LPG recovery was cost-effective to have a total heat content (based on higher heating value) equal to 15,000 MMBtu per year. Cost-effectiveness was calculated to be $58,000 per ton of NOx reduced over the lifetime of the auxiliary gas refrigeration/compressor system or new flare, which is well below the cost-effectiveness threshold of $349,000 per ton of NOx reduced as established by 2022 AQMP. The annual throughput of 15,000 MMBtu per year or greater is below the cost-effectiveness threshold of $349,000 per ton of NOx reduced.

Staff is proposing amendments that will require any facility that exceeded an annual throughput with total heat content (based on higher heating value) of 15,000 MMBtu/year for two consecutive years since 2017 to reduce flaring at non-hydrogen clean service flares (LPG flares). This proposal will impact two facilities and will require those facilities to implement corrective actions.

### Estimated Emissions Impact

Staff estimated the corresponding lifetime NOx emission reductions from implementation of auxiliary gas refrigeration/compressor system at two facilities that operate LPG flares to be equal to 7.3 ton per year at the throughput threshold of 15,000 MMBtu per year for LPG flares.

## *PAR 1118 and AB 617 CERP Actions for Wilmington, Carson, West Long Beach Community*

Staff aligned the proposed requirements under PAR 1118 with the AB 617 CERP actions for WCWLB community. The table below shows the requirements and considerations by PAR 1118 that address the listed actions by AB 617 CERP.

**Table 3-9. PAR 1118 Impacts on AB 617 CERP Actions for WCWLB Community**

| AB 617 CERP Actions | PAR 1118 Related Impact(s) |
|---|---|
| Lower performance targets and/or adjust mitigation fees | - Proposing to lower $SO_2$ performance target<br>- Proposing to adjust mitigation fees annually using Customer Price Index |
| Additional flare minimization plans | - Lowered performance target would trigger FMP submittals more frequently |
| Lower-emission flaring technologies | - Flare manufacturers improve design, efficiency, and performance<br>- Facilities replace and upgrade in accordance with turnaround<br>- More frequent FMPs would trigger actions that may include replacement of flare components |
| Back-up power systems for key process units | - More frequent FMPs would trigger actions that reduce flaring due to internal power loss<br>- According to SCARs, power failures mainly result from electrical switch failures, transformer ground faults, blown fuse, short circuits, and animal intrusions |

PAR 1118 fulfills most of the priority actions included in the AB 617 CERP for WCWLB community; however, staff determined some of the actions as not to be technically feasible, as stated below.

**Action Item: Increase Capacity of Vapor Recovery Systems to Store Gas During Shutdowns**

Recovered vent gas by vapor recovery system is not intended to be stored as large volume of stored gas can create an explosive environment. All refineries have FGR systems designed to capture a designed volume of the vent gas that would otherwise be combusted in the existing flare equipment, but use of large storage systems was deemed to be infeasible.

**Action Item: Header Modifications for Gas Diversion with Process Controls**

Owners and operators of facilities implemented modification of flares header as part of the requirements by 2005 amendments to Rule 1118 by installing or upgrading flare gas recovery systems. Staff did not identify any emission reductions that could feasibly be achieved with header modifications.

**Action Item: Remote Optical Sensing for Flare Emission Characterization**

Video Imaging Spectro-Radiometry (VISR) technology is commercially available and there are technology vendors that provide this technology for the purpose of remote optical sensing. However, technologies that work with VISR method are currently under review by U.S. EPA but not yet approved. Staff will consider these technologies for the purpose of flare emissions characterization or as a tool for South Coast AQMD compliance staff to verify flare emissions in the future when the technology is approved by U.S. EPA.

# CHAPTER 4 : SUMMARY OF PROPOSALS

### *INTRODUCTION*

The main objective of PAR 1118 is to reduce emissions from refinery flares by lowering the $SO_2$ performance target for all flares, establish a new NOx performance target for hydrogen production plants, and establish a throughput threshold for LPG clean service flares. The proposed amendments and projected emission reductions are aligned with the emission reduction targets that were included in the WCWLB community CERP and are expected to be achieved by 2030. PAR 1118 also removes outdated rule language, reorganizes the rule structure to be consistent with recently amended or adopted rules, and includes separate and new requirements for clean service flares located at refineries and hydrogen production plants, updates requirements for notifications sent through FENS, and establishes new requirements for standardized flare event data reporting through FENS.

Staff initially considered requiring the owner or operator of facilities to post live flare images on FENS or another public webpage as part of PAR 1118. However, due to security concerns with respect to the applicability of security provisions related to the facilities subject to Rule 1118 under the Chemical Facility Anti-Terrorism Standards (CFATS) administrated by the federal Cybersecurity and Infrastructure Security Agency (CISA) and the US Coast Guard, staff withdrew the proposal to ensure PAR 1118 is consistent and not contradictory to existing orders, state law, and federal requirements.

### *PROPOSED AMENDED RULE STRUCTURE*

In PAR 1118, staff separated the purpose and applicability to be consistent with recently adopted and amended rules by South Coast AQMD and added new subdivisions to support the rule requirements.

PAR 1118 has two new subdivisions and two new attachments. Staff clarified and streamlined rule language and consolidated rule provisions. PAR 1118 has new and separate requirements for hydrogen and non-hydrogen clean service flares. The following figure compares the rule structure of the 2023 Rule 1118 (last amendment) versus PAR 1118.

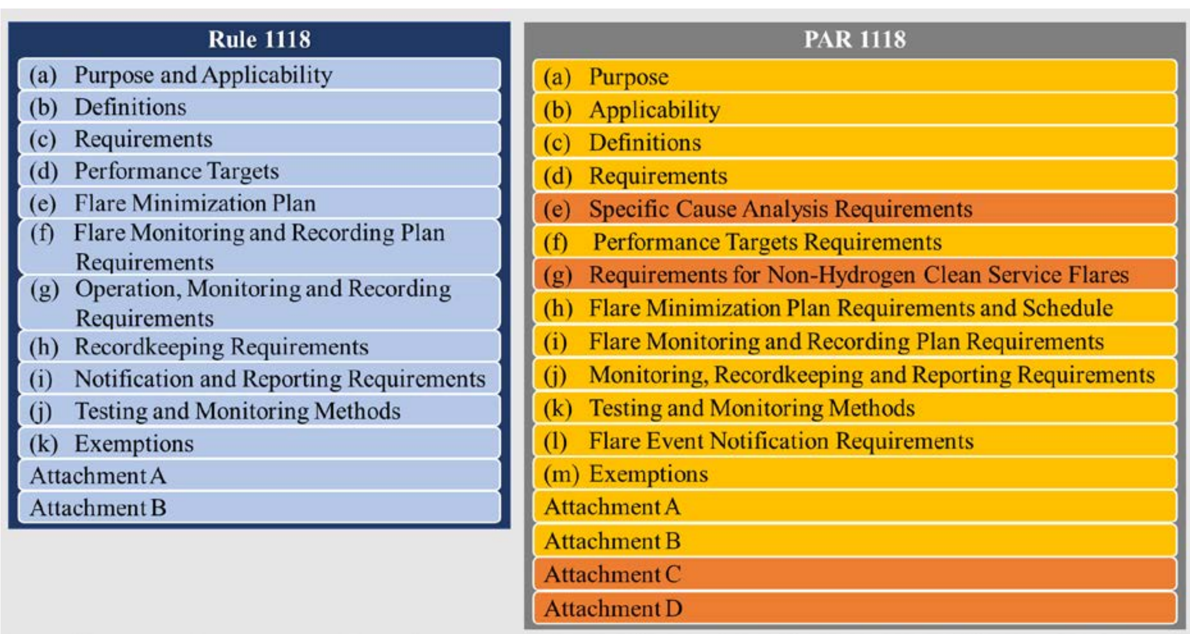



**Figure 4-1. Rule Structure – Rule 1118 vs. PAR 1118**

### *SUMMARY OF PROPOSED AMENDED RULE 1118*

The following is a summary of the proposed amendments to Rule 1118.

**Subdivision (a) – Purpose**

The purpose of PAR 1118 is to monitor and record operation data on refineries and related flaring operations, and to control and minimize flaring and flare-related emissions. The intention of this rule is not to be preemptive with respect to the operations and practices of any refinery, sulfur recovery plant, or hydrogen production plant that are essential and unavoidable for safety concerns.

**Subdivision (b) – Applicability**

All flares that are being operated at refineries, sulfur recovery plants, and hydrogen production plants are subject to PAR 1118.

**Subdivision (c) – Definitions**

***New and Amended Definitions***

Staff is proposing to add or amend the following definitions to the rule language:

**Paragraph (c)(1) – Alternative Feedstock**

Alternative feedstock is any feedstock, intermediate, product, or byproduct material containing organic material that is not derived from crude oil product, coal, natural gas, or any other fossil-fuel based organic material. Staff added this definition to ensure Rule 1118 remains applicable to refineries that transition some or all their crude oil feedstock to alternatives.

**Paragraph (c)(4) – Essential Operational Need**

Staff amended this definition to align the language with the new proposed requirement for clean service flares located at refineries (i.e., LPG flares). "Essential operational need" is defined to exclude venting of clean service streams when measures, including any refrigeration/chiller system, modification or replacement of flare, or other applicable means under normal operation, have been implemented to reduce annual throughput at non-hydrogen clean service flares and when LPG flares are being operated at a level above the proposed annual throughput level in subdivision (g). However, venting of the gas stream to the LPG flare during specific situations, such as LPG tank cleaning, maintenance, and inspections that will require the LPG tanks to be de-inventoried, may be inevitable and considered essential. Recovering LPG gas stream is not possible during such operations partially due to use of nitrogen as a purge gas in the stream and inability to store the gas due to tank outage.

**Paragraph (c)(5) – Facility**

This is a new definition to include any refinery, sulfur recovery plant, or hydrogen production plant to streamline rule language.

**Paragraph (c)(6) – Flare**

Current definition accounts for two types of flares: general service flares and clean service flares. Staff updated the definition of flare to separate the clean service flares that solely combust hydrogen vent streams from other types of clean service flares, because PAR 1118 considers different requirements for the clean service flares at refineries and Hydrogen production plants.

Hydrogen clean service flares are designed and configured by installation to combust only Clean Service Streams from a Hydrogen Production Plant; or

Non-hydrogen clean service flares are designed and configured by installation to combust only Clean Service Streams from a Facility other than Hydrogen Production Plant. LPG flares located inside the refineries are classified as non-hydrogen clean service flares.

**Paragraph (c)(7) – Flare Event**

Current definition of "flare event" contains statements that are not applicable to both planned and unplanned types of flare event. Staff moved the language pertained to determination of start and end of a flare event to Subdivision (d) – Requirements. Staff also moved the requirements for reporting flare events to Subdivision (l) – Flare Event Notifications Requirements.

**Paragraph (c)(8) – Flare Event Notification System (FENS)**

Staff updated this definition to remove the term "web-based" from the defined term. The definition was relocated with respect to the alphabetical order.

**Paragraph (c)(11) – Flare Monitoring and Recording Plan (FMRP)**

Staff added the definition for FMRP that is a compliance plan prepared by a facility and submitted to the Executive Officer for approval.

**Paragraph (c)(13) – Flare Tip Velocity**

Staff added the reference to Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries for calculation of flare tip velocity, as part of incorporation of U.S. EPA RSR into PAR 1118.

**Paragraph (c)(14) – Hydrogen Production Capacity**

Staff added the definition for production capacity of a hydrogen production plant as its maximum rated capacity to produce hydrogen in million standard cubic feet of hydrogen per year calculated based on the maximum daily rated capacity. PAR 1118 Attachment C provides the list of hydrogen production plants and the hydrogen production capacity of those plants as listed in their current Title V permit or latest FMRP.

**Paragraph (c)(17) – Oxides of Nitrogen (NOx) Emissions**

NOx emissions are the sum of nitric oxide and nitrogen dioxide emitted, calculated, and expressed as nitrogen dioxide.

**Paragraph (c)(18) – Performance Target**

Performance target is an annual threshold on the amount of sulfur dioxide emissions or NOx emissions that can be emitted from a facility over one calendar year, otherwise the owner or operator is required to take certain actions, including preparing FMPs and paying mitigation fees.

**Paragraph (c)(20) – Planned Flare Event**

Staff updated the definition by adding the term "scheduled". The provision to determine "when to consider a startup process as a *planned* event after the end of an *unplanned* event" was moved to Subdivision (d) – Requirements.

## Paragraph (c)(21) – Processing Capacity

Staff added the definition to streamline the rule the amount of crude oil and/or alternative feedstocks, which includes organic material that is not derived from crude oil product, coal, Natural Gas, or any other fossil-fuel based organic material, that a facility can process annually. PAR 1118 Attachment C provides the list of refineries and sulfur recovery plants, and the processing capacity of those facilities as listed in their current Title V permit, latest FMRP, or the California Energy Commission's list of California Oil Refinery Locations and Capacities[7]. If processing capacity is not available for a facility through any of the listed sources, the amended rule requires the owner or operator of the facility to report the processing capacity in million barrels for the prior calendar year within 30 days of the end of every calendar year.

## Paragraph (c)(24) – Refine

Refine means to convert crude oil or Alternative Feedstock to produce more usable products such as gasoline, diesel fuel, aviation fuel, lubricating oils, asphalt or petrochemical feedstocks, or any other similar product.

## Paragraph (c)(25) – Refinery

Staff updated the definition of "petroleum refinery" to remove the term "petroleum" from the definition and include a facility that is permitted to refine alternative feedstocks. The new definition of refinery now includes any facility that is permitted to refine crude oil or alternative feedstocks, and all portions of the refining operation, including those at non-contiguous locations operating flares, are considered as one refinery. The definition was relocated with respect to the alphabetical order.

## Paragraph (c)(26) – Relative Cause

Staff added a new definition for the identified category of the cause of any flare event where more than 5,000 cubic feet of vent gas is combusted at the flare. The amended rule does not require specific cause analysis report to be prepared for all flare events that exceed this threshold, however the relative cause is required to be reported in the quarterly reports being submitted to South Coast AQMD and it may include emergency, shutdown, startup, turnaround, essential operational need, or unknown if undeterminable.

## Paragraph (c)(33) – Unplanned Flare Event

Staff proposed a new definition for unplanned flare event as any flaring of vent gas during operations, such as unplanned shutdown, subsequent startup, valid breakdown, unforeseen maintenance, customer order kick back, or because of any situation beyond the operator's control including external power curtailment and/or external water curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters, acts of war or terrorism.

## ***Removed Definition in Subdivision (c)***

Staff removed the following definition from the rule language as it was referenced only in one place in the rule; thus, staff added the explanation where the term was used:

[7] California Energy Commission's – California Oil Refinery Locations and Capacities: https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries

*NOTICE OF SULFUR DIOXIDE EXCEEDANCE* is a notice issued by the Executive Officer to the owner or operator when the petroleum refinery has exceeded a performance target of this rule.

**Subdivision (d) – Requirements**

**Subparagraph (d)(1)(C)**

Staff added the references to incorporate U.S. EPA RSR provisions into PAR 1118. The first reference is to Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries for calculation of net heating value of vent gas. The second reference is to a new monitoring, recordkeeping, and reporting requirement in subdivision (j) that incorporates U.S. EPA RSR provisions for flare vent gas composition monitoring to obtain supportive data that may be used to calculate net heating value of vent gas.

**Subparagraphs (d)(1)(E) and (d)(1)(F)**

Staff streamlined the rule language to list all operational requirements in paragraph (d)(1) and moved the provisions to minimize combustion of vent gas and hydrogen sulfide in flares previously located at the end of this subdivision to be under paragraph (d)(1).

**Paragraph (d)(2)**

This provision was moved to this subdivision from the definition of Flare Event.

**Paragraph (d)(3)**

This provision was moved to this subdivision from Subdivision (i) – Flare Monitoring and Recording Plan Requirements.

**Paragraph (d)(5)**

This provision specifies the requirement for an owner or operator to conduct a specific cause analysis for any flare event that exceeds at least one of the thresholds (i.e., 100 pounds of VOC, 500 pounds of $SO_2$, or 500,000 standard cubic feet of combusted vent gas). A flare event resulting from a startup, shutdown, or turnaround activity is excluded from the specific cause analysis requirement. However, if at any time during such planned activities there is a deviation from the facility’s prescribed operating practices or procedure for the planned activity which results in an unplanned flare event, a specific cause analysis shall be required, and the flare event shall be considered the result of “non-standard operating procedure”.

**Paragraph (d)(7)**

The provisions of this paragraph are aligned with the requirements of U.S. EPA’s 2015 federal Refinery Sector Rule. During any flare event that exceeds both or either of visible emission and flare tip velocity limits determined in South Coast AQMD Rule 401, subparagraph (d)(1)(B), or subparagraph (d)(1)(C), the owner or operator may not operate the flare above its smokeless capacity level, if the flare event is:

- The result of operator’s fault or poor maintenance
- The second flare event from a single flare in any 3-calendar-year period for the same root cause as the first one for the same equipment

- The third flare event from a single flare in any 3-calendar-year period for any reason (any source)

Any flare events due to a cause beyond the operator's control, including external power curtailment (excluding interruptible service agreements), natural disasters or acts of war or terrorism should not be included in the event count.

**Paragraph (d)(10)**

The owners or operators of facilities are required to determine the relative cause of any flare event with the vent gas stream of more than 5,000 standard cubic feet to be reported in their quarterly reports, using the flare cause codes as previously listed in Table 2-1 of this staff report.

***Removed Provisions in Subdivision (d)***

Staff consolidated all provisions and requirements related to submission of specific cause analysis and corrective actions implementation schedule to a new subdivision (i.e., Subdivision (e) – Specific Cause Analysis Requirements).

Staff moved the monitoring and recordkeeping provisions listed under Requirements to Subdivision (j).

Staff also removed outdated provisions that previously required the facility to prepare and submit scoping document as part of the amendment to Rule 1118 in 2017.

**Subdivision (e) – Specific Cause Analysis Requirements**

This subdivision includes the provisions and schedules related to specific cause analysis. Staff moved the language down from "Subdivision (d) – Requirements" to this new subdivision.

**Paragraphs (e)(1) and (e)(2)**

Rule 1118 requires specific cause analysis to be conducted for:

- every flare event that exceeds the specified emissions threshold(s) (paragraph (d)(5));
- every single flare with a flare event during the same period of time when the smokeless capacity of the flare is exceeded and either the applicable visible emission limit or the applicable flare tip velocity limit is exceeded.

Staff added new provisions in paragraphs (e)(1) and (e)(2) to incorporate U.S. EPA RSR provisions into PAR 1118. The new language identifies the situations where a single specific cause analysis is deemed sufficient for flare events that involve exceedance of multiple operational limits at one or more flares. For example, paragraph (d)(6) requires a specific cause analysis to be conducted if:

- smokeless capacity of the flare is exceeded, and visible emission limit is exceeded **or**
- smokeless capacity of the flare is exceeded, and velocity limit is exceeded.

Subparagraph (e)(1)(A) states that one specific cause analysis is sufficient if the smokeless capacity is exceeded and both the visible and velocity are exceeded.

**Paragraphs (e)(3) and (e)(4)**

Paragraph (e)(3) requires the specific cause analysis to be conducted within 30 days of the flare event; paragraph (e)(4) allows the facility to request an extension within 14 days of the flare event.

### Paragraphs (e)(5) and (e)(6)

All corrective actions identified in a specific cause analysis report are due to be implemented within 45 days of the flare event. The owner or operator may be eligible for a one-time extension to implement the corrective actions if adequate supporting documents are provided to the Executive Officer in a timely manner.

### Paragraphs (e)(7) and (e)(8)

Paragraphs (e)(7) and (e)(8) includes provision for the Executive Officer to review and approved the extension request and the specific cause analysis.

### Paragraphs (e)(9)

Paragraphs (e)(9) includes the deadline to submit the report of the corrective action(s) taken to address the flare event. Staff added the requirement for the owner or operator of a facility that submitted a specific cause analysis report to provide the record of corrective action(s) completed, aligned with the similar requirement established by U.S. EPA RSR.

## Subdivision (f) – Performance Targets Requirements

### Paragraph (f)(1)

Staff updated $SO_2$ performance target to gradually decrease over time. PAR 1118 requires facilities to meet a performance target of 0.35 ton of sulfur dioxide per million barrels of processing capacity for reporting emissions for calendar year 2026 through 2028, and a performance target of 0.25 ton of sulfur dioxide per million barrels of processing capacity for reporting emissions for calendar year 2029 and thereafter.

Staff proposed to change the reference for facilities processing capacity from “calendar year 2004” to “as listed in their current Title V permit, latest FMRP, the California Energy Commission’s list of California Oil Refinery Locations and Capacities for each calendar year, or as reported by the facility”, as outlined in PAR 1118 Attachment C. PAR 1118 Attachment C Table C1 lists processing capacities for refineries.

### Paragraph (f)(2)

Staff proposed a new performance target of 0.3 pound of NOx per million standard cubic feet of hydrogen production capacity to control emissions from hydrogen clean service flares. These flares are solely used for vent gas streams from hydrogen production plants. PAR 1118 Attachment C Table C2 lists production capacities for Hydrogen production plants.

This provision becomes effective when owner or operators of hydrogen production plants report emissions for calendar year 2025 and thereafter.

### Paragraph (f)(3)

This paragraph was updated to also include hydrogen production plants that are subject to meet the NOx performance target in paragraph (f)(2).

### Paragraph (f)(4)

Staff updated this paragraph to clarify the schedule to submit a flare minimization plan and appropriate mitigation fees for the owner or operator of a facility that exceeds the applicable $SO_2$ or NOx performance target for any calendar year. Staff also added new provisions to address the owner or operator of a facility with any periods of invalid monitoring data within the calendar year who seeks to use an alternative method to substitute the missing data. The owner or operator is required to submit supporting data for alternative data substitution for the Executive Officer approval within 60 days following the end of the calendar year when performance target exceedance occurred. If the Executive Officer deems the submitted data as insufficient, the owner or operator will be granted 30 days to submit additional supporting data. If the executive Officer provides a written notification of insufficiency of resubmitted data, the standard data substitution procedures in PAR 1118 Attachment B is applicable for the purpose of data substitution. If the applicable data (approved or standard alternative data substitution) that is used to calculate the annual flare emissions confirms that the facility exceeded the applicable performance target, the owner or operator is required to submit a flare minimization plan and appropriate mitigation fees within 90 days of receiving the Executive Officer's final notice of alternative data substitution insufficiency or approval.

Staff adjusted mitigation fees using Consumer Price Index (CPI) for 2022 to serve as the baseline. Staff also transferred requirements on mitigation fees to a new attachment (PAR 1118 Attachment D). This attachment provides the calculations of facility-specific performance targets, the new baseline fees, and methodology to adjust the fees annually using CPI.

**Subdivision (g) – Non-Hydrogen Clean Service Flares Requirements**

This is a new subdivision to establish new requirements for owner or operator of non-hydrogen clean service flares (i.e., LPG flares).

**Paragraph (g)(1)**

The owner or operator of an LPG flare is required to submit a permit application for any LPG flare that has exceeded the proposed annual throughput level with total heat content of 15,000 MMBtu per year (based on higher heating value of total Vent Gas and Purge Gas) in any two consecutive years since 2017.

This provision is applicable to any LPG flare that exceeded the proposed threshold preceding the date of PAR 1118 adoption and includes requirements and schedule to install necessary equipment to reduce flaring emissions at such flares.

**Paragraph (g)(2)**

Staff added the requirement to maintain LPG clean service flares to meet an annual throughput level with total heat content of 15,000 MMBtu per year (based on higher heating value of total Vent Gas and Purge Gas) for two consecutive calendar years. Consideration to allow for exceedance to occur at most every other year was established to accommodate planned tank inspection, maintenance, and cleaning which is essential for safety and operational concerns.

This provision is effective when owner or operators of LPG flares report emissions from these flare for calendar year 2026 or 24 months after the permit is issued, whichever is later, and continuously thereafter. The schedule considers the permitting timeframe and provides time for equipment installation or implementation.

**Subdivision (h) – Flare Minimization Plan Requirements and Schedule**

**Paragraph (h)(1)**

Staff amended the language to allow facilities to either submit a new FMP or revise an existing FMP. In some instances, the cause of exceeding the performance standard can be completely different from a past exceedance; therefore, the prior FMP might not be relevant. In additions, the schedule for submitting the FMPs now reference paragraph (f)(4) and the paragraph has been updated to be applicable to both $SO_2$ and NOx performance targets as established in subparagraphs (f)(1)(A) and (f)(2)(A).

### Paragraph (h)(2)

Staff added a new requirement for owner or operator of a facility to submit an FMP for any calendar year when annual throughput threshold was exceeded at a non-hydrogen clean service (LPG) flare.

### Subdivision (i) – Flare Monitoring and Recording Plan Requirements

Staff streamlined the language in this subdivision but did not propose any new requirement or consideration. Provisions related to commencement of operation at a new or an existing non-operating facility that plans to recommence operation were moved to Subdivision (d) – Requirements (paragraph (d)(3)).

### Subdivision (j) – Monitoring, Recordkeeping, and Reporting Requirements

### Paragraph (j)(1)

Staff moved the provisions from Subdivision (d) – Requirements that are related to MRR to this subdivision to streamline the rule language.

### Paragraph (j)(3) and Table 2

Staff proposed to remove the allowance to use an on/off flow indicator for the purpose of monitoring and recording the vent gas flow at general service flares and all clean service flares (hydrogen and non-hydrogen), in PAR 1118 Table 2. This change is effective pursuant to the compliance schedule as stated in PAR 1118 paragraph (j)(10).

### Paragraph (j)(5)

Staff added a new provision to incorporate U.S. EPA RSR requirements for flare vent gas composition monitoring that may be used to calculate net heating value of vent gas. Per EPA RSR, this provision may not be applicable to all type of flares.

### Subparagraph (j)(7)(B)

This subparagraph was the language previously included under paragraph (j)(6) and is now separated and updated to be applicable to all flares rather than just general service flares. Staff updated the provision to be consistent with the new consideration to require the use of continuous vent gas flow meter for clean service flares in addition to general service flares (PAR 1118 Table 2).

### Paragraph (j)(8)

Staff removed the reference to “any other equivalent device” in lieu of the requirement to install and maintain a thermocouple to detect the presence of a pilot flame as all flares are required to have a thermocouple present to detect the pilot flame.

### Paragraph (j)(9)

Staff removed the outdated language from this provision.

## Paragraph (j)(10)

Staff updated this provision to be applicable to general service flares, and hydrogen clean service flares. Owner or operator of a general service flare is required to have a vent gas flow meter installed at the time of rule adoption. Owner or operator of a hydrogen clean service flare is granted 18 months after the date of rule adoption to install and operate a continuous vent gas flow meter and meet the criteria of this provision.

This provision also requires monitoring and recording of pilot and purge gas flows separately using a flow meter or an equivalent approved device.

## Paragraph (j)(12)

The recordkeeping requirements were updated to include the requirement for the owners or operators of facilities to maintain the records of the relative cause analysis for any flare event with more than 5,000 standard cubic feet of vent gas being combusted at the flare for a period of five years.

## Paragraph (j)(13)

This provision is not a new language and was moved down from the beginning of this very subdivision.

## Paragraph (j)(14) – Annual Emissions and Throughput Reporting

Staff added this new requirement for reporting annual $SO_2$ or NOx emissions, or annual LPG flare throughput by the owner or operator of a facility when they meet the criteria that requires them to submit an FMP and corresponding mitigation fees pursuant to paragraph (f)(3) or paragraph (g)(2). This information is required to be submitted to South Coast AQMD through FENS no later than 30 days after the end of the calendar year for which they are required to submit the FMP and mitigation fees. Staff will work on implementing changes to FENS after rule adoption to address this requirement. Until those changes have been finalized, facilities will be required to report flares' annual emissions and throughput (if applicable) through email (Rule1118@aqmd.gov).

## Paragraph (j)(15) – Quarterly Reports

This provision is old language and was moved up from Subdivision (l) – Flare Event Notification Requirements.

Facilities have been submitting quarterly reports to South Coast AQMD for more than a decade. Quarterly reports include comprehensive flare event data which has to be certified for accuracy by a responsible facility official. A responsible facility official may be a president or vice-president of the corporation in charge of a principal business function or a duly authorized person who performs similar policy-making functions for a corporation, or may be a general partner or proprietor for a partnership or sole proprietorship, respectively. Currently, quarterly flare event data is only available to the public through submitting a Public Records Request to South Coast AQMD. PAR 1118 proposed the requirement for quarterly flare event data to be more comprehensive (including the recorded digital images of the flare pursuant to paragraph (j)(9)) and be submitted through FENS to accommodate the request by community members for access to these data on a timely manner. Staff intends to standardize the format for the facilities to submit the quarterly reports to streamline the process of making the data publicly available. Staff will work on the changes to FENS after rule adoption through a public process that involves both the regulated facilities and the community. Until those changes have been finalized, facilities will be required to submit the quarterly reports through email (Rule1118@aqmd.gov).

### Paragraph (j)(16) – Monthly Emissions Reports

Staff proposed a new reporting requirement for the owner or operator of facilities to submit preliminary emissions and operational data every month, in addition to the comprehensive quarterly reports. Monthly reports are required to be submitted through FENS. This proposed requirement is expected to accommodate early public access to preliminary data available sooner than quarterly data reports are prepared and submitted. Staff proposed the allowance for the owners and operators to not being required to submit complete information and details (e.g., cause) in the monthly reports while flag data as "preliminary" (certified by a responsible facility official) with the ability to go back and update data at a later time. Staff will work on implementing changes to FENS after rule adoption to address this requirement. This requirement will go into effect on January 1, 2025, to allow staff adequate time to make the necessary updates in FENS. If the changes to FENS have not been completed by January 1, 2025, facilities will be required to submit the monthly reports through email (Rule1118@aqmd.gov).

### Paragraph (j)(17) – Specific Cause Analysis Reports

Staff added a new reporting requirement for specific cause analyses and complete details to be submitted through FENS. Staff will work on implementing changes to FENS after rule adoption to address this requirement. Until those changes have been finalized, facilities will be required to submit SCARs through email (Rule1118@aqmd.gov).

### Paragraph (j)(18)

Staff added the requirement for electronic submission of annual emissions reporting, annual throughout reporting, quarterly reports, monthly reports, and specific cause analysis report to an electronic address (Rule1118@aqmd.gov) or through an alternative method that is approved by the Executive Officer during the FENS downtime or when specific feature(s) is not available on FENS. This provision accommodates the reporting requirements for which the appropriate feature(s) may not be yet available in FENS at the time of rule adoption. Staff will work on implementing changes to FENS after rule adoption to incorporate those features.

### Paragraph (j)(19)

Staff added a new requirement for the owner or operator of facilities to report processing capacity if no processing capacity value is listed for the facility in Table C1 of PAR 1118 Attachment C.

## Subdivision (k) – Testing and Monitoring Methods

Staff moved up this subdivision to follow Subdivision (j) – Monitoring, Recordkeeping and Reporting Requirements.

### Subparagraph (k)(1)(C)

Staff updated the required frequency to verify the accuracy of vent gas flow meters to every calendar year with at least 6 months' time-lag from the last verification procedure.

## Paragraph (k)(3)

Staff added the reference to Rule 218.2 and Rule 218.3 to this paragraph, because a CEMS that is subject to Rule 2012 must be certified pursuant to the implementation schedule in paragraph (d)(3) of Rules 218.2 and 218.3.

**Subdivision (l) – Flare Event Notification Requirements**

Provisions related to quarterly reports were moved to Subdivision (j) – Monitoring, Recordkeeping, and Reporting Requirements (paragraph (j)(13)).

## Paragraph (l)(2)

Staff is proposing to require a flare event notification through FENS for all flare events (planned and unplanned) within one hour of exceeding at least one of the following thresholds: 100 pounds of VOC emissions; 500 pounds of sulfur dioxide emissions; or 500,000 standard cubic feet of flared vent gas. Previously, the owner or operator was required to create a notification for a "planned" flare event at least 24 hours before the planned flare event and send a second notification one hour after the start of the flare event. This proposed change was to align the requirements for planned and unplanned events with respect to reporting the start of a flare event.

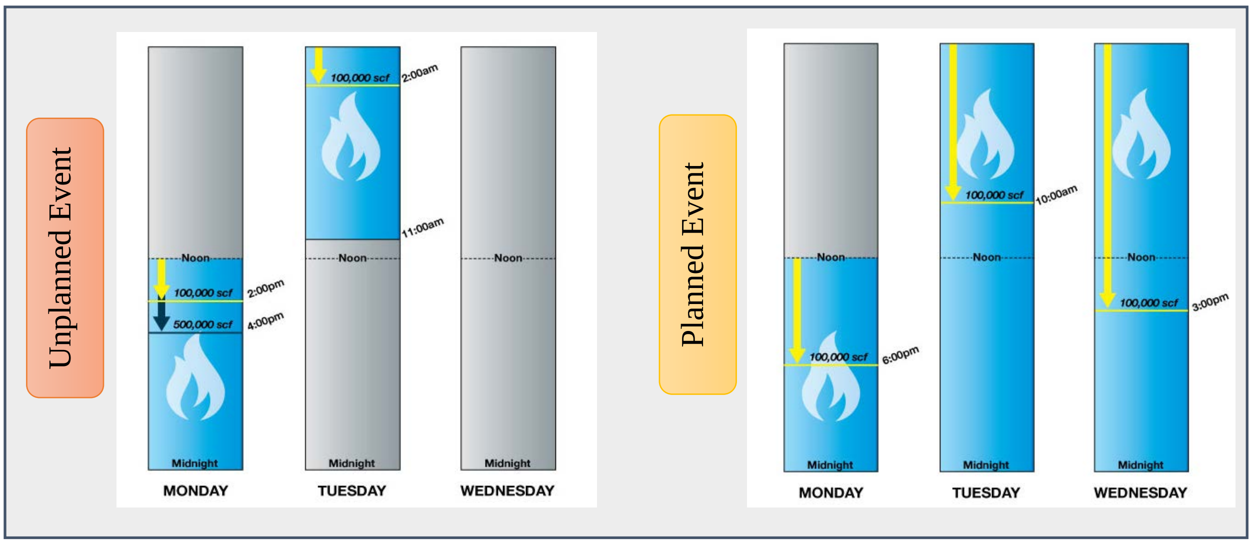



**Figure 4-2. Demonstration of Notification Triggers for Unplanned vs. Planned Flare Event**

Staff also updated the provision to require the owner or operator of the facilities to provide information about the ending time of flare event within 24 hours of ending the flare event and information about exceedance of flare smokeless capacity during the flare event through FENS within 72 hours of ending the flare event.

## Paragraph (l)(3) – Planned Flare Event Notifications

Staff removed the notification requirement within one hour prior to start of a planned flare event to be consistent with the proposed change in paragraph (l)(2). Additional notification is still required for every planned flare event at least 24 hours prior to the start time.

#### Paragraph (l)(4) – Unplanned Flare Event Notifications

Staff added clarification regarding notification requirements for unplanned flare events that last longer than 24 hours. The operator is required to end such unplanned flare event within 24 hours or at the end of the starting calendar day and generate an unplanned flare event notification for every calendar day that flaring continues to occur.

#### Paragraph (l)(6) – Characterizing and Reporting Flare Events

Staff combined all provisions that are related to characterization of flare events for the purpose of reporting through FENS to this paragraph. These provisions were previously included in the definitions of “Flare Event” and “Planned Flare Event”.

***Removed Provisions***

Staff moved the quarterly reports requirements listed under Flare Event Notification Requirements to Subdivision (j).

### Subdivision (m) – Exemptions

#### Paragraph (m)(2)

Staff updated this exemption to allow for NOx emissions (in addition to sulfur dioxide emissions, and visible emissions and flare tip velocity beyond applicable limits) not to be counted towards applicable performance target if it is generated as a result of a flare event that was caused by external power and/or external water curtailment beyond the operator’s control (excluding interruptible service agreements), natural disasters, or acts of war or terrorism.

#### Paragraph (m)(3)

Staff added this exemption to allow for flare’s total vent gas throughput not to be counted towards the proposed annual throughput if it is due to a flare event that was caused by external power and/or external water curtailment beyond the operator’s control (excluding interruptible service agreements), natural disasters, or acts of war or terrorism.

### Attachment A – Flare Monitoring System Requirements

Staff updated the reference to South Coast AQMD Rule 218.1 to Rule 218.2 and Rule 218.3, as applicable. No other changes were made to flare monitoring system requirements.

Also, staff proposed to allow the owner or operator of facilities to postpone the required calibration of monitoring systems for up to 72 hours during an ongoing flare event. According to Rule 1118, the owner or operator of a facility is required to calibrate the flare and sulfur monitoring systems daily and flare emissions cannot be measurement during calibration procedures which can lead to punitive data substitution procedures. Staff does not think the punitive data substitution procedures should apply for required calibration procedures so is proposing to allow for delayed calibrations during an ongoing flare event.

### Attachment B – Guidelines for Calculating Flare Emissions

#### Section (1) – Emission Calculation Procedures

Staff remove the outdated procedures to calculate air pollutants emissions in the vent gas.

### Section (3) – Data Substitution Procedures

Staff updated the some of the terms in the equations for calculation of estimated flow rate, estimated higher heating value, and estimated total sulfur concentration.

Missing data substitution procedures are required pursuant to PAR 1118 Attachment B, and the owner or operator is required to use the maximum flow rate measured and recorded for a flare during the previous 20 quarters preceding the flare event for the purpose of data substitution. Staff added provisions to allow for data substitution (i.e., flow rate, high heating value, and sulfur concentration) using recorded data during one hour before and one hour after the period that data is not recorded, if it lasts for 15 minutes or less.

**Attachment C**

Staff added a new attachment to list the updated processing capacity for refineries and production capacity for hydrogen production plants. Staff proposed to update the facilities processing capacity used to calculate facility specific $SO_2$ performance target that was previously referenced to the processing capacity values from 2004. Any facility without publicly available processing capacity information is required to report this value to the Executive Officer pursuant to paragraph (j)(19). The processing capacity is required to be updated after the date of rule adoption if the value changes in the facility’s Title V permit, the facility's FMRP, or the California Energy Commission’s list of California Oil Refinery Locations and Capacities, or the owner or operator of the facility reports an updated value pursuant to paragraph (j)(19).

**Attachment D**

Staff added a new attachment to provides guidelines for calculating facility specific $SO_2$ performance target for a refinery, NOx performance targets for hydrogen production plants, and mitigation fees adjusted based on consumer price index.

### Section (3) – Calculations for Baseline Mitigation Fees

Mitigation fees were last updated in 2004. Staff is proposing to adjust the mitigation fees, using the 2022 Consumer Price Index (CPI), according to the schedule in the table below. Staff also proposed to use these updated mitigation fees as baseline mitigation fees.

**Table 4-1. Baseline Mitigation Fees for Exceeding $SO_2$ Performance Target**

| Excess Emissions (%) | Mitigation Fees ($/ton of Excess $SO_2$) |
|---|---|
| ≤10 | 39,000 |
| >10 to ≤20 | 79,000 |
| >20 | 158,000 |

## Section (4) – Calculations for Adjusted Mitigation Fees

Staff proposed to adjust the mitigation fees annually based on the listed CPI for each year by the State of California Department of Industrial Relations[8]. The owner or operator of facilities that are required to pay the mitigation fees pursuant to paragraph (f)(3) or (g)(2) must pay the fees as calculated using CPI for the calendar year that the performance target was exceeded, or the most recently available CPI using the equation in PAR 1118 Attachment D.

[8] State of California Department of Industrial Relations: https://www.dir.ca.gov/OPRL/

# CHAPTER 5 : IMPACT ASSESSMENT

**INTRODUCTION**

**EMISSIONS INVENTORY AND EMISSION REDUCTIONS**

**COST-EFFECTIVENESS AND INCREMENTAL COST-EFFECTIVENESS**

**SOCIOECONOMIC IMPACT ASSESSMENT**

**CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)**

**REFERENCE**

**COMPARATIVE ANALYSIS**

### *INTRODUCTION*

Rule 1118 was originally adopted by South Coast AQMD Governing Board on February 13, 1998, to control and reduce emissions from refinery flares. PAR 1118 is expected to impact 31 flares located at 12 facilities with updated requirements for the $SO_2$ performance target. Four out of 12 facilities (i.e., four flares) are expected to be impacted by the new NOx performance target requirements for clean service flares at hydrogen production plants. Three out of 12 facilities (i.e., three flares) are expected to be impacted by the new throughput threshold requirements for clean service flares at refineries (LPG flares). The requirement for installation of a continuous vent gas flow meter impacts four hydrogen clean service flares and is expected to be in operation consistent with a specified schedule.

### *EMISSIONS INVENTORY*

Flares regulated by Rule 1118 are sources of different pollutant emissions, including $SO_2$, NOx, VOC, and PM10. The table below shows the level of emitted emissions from all flares since 2012 reported by the facilities.

**Table 5-1. Rule 1118 Emissions Estimates from All Facilities (2012–2022)**

| Year | $SO_2$ Emissions (ton/year) | NOx Emissions (ton/year) | VOC Emissions (ton/year) | $PM_{10}$ Emissions (ton/year) |
|---|---|---|---|---|
| **2012** | 122.83 | 45.15 | 29.36 | 9.75 |
| **2013** | 81.62 | 34.35 | 19.93 | 8.00 |
| **2014** | 103.13 | 22.29 | 9.12 | 4.84 |
| **2015** | 180.93 | 41.56 | 13.94 | 7.37 |
| **2016** | 67.29 | 26.36 | 13.67 | 7.79 |
| **2017** | 66.05 | 19.58 | 7.09 | 4.30 |
| **2018** | 63.43 | 17.54 | 5.38 | 2.00 |
| **2019** | 59.02 | 19.41 | 22.12 | 3.07 |
| **2020** | 62.27 | 18.54 | 58.39 | 4.09 |
| **2021** | 116.65 | 22.35 | 44.58 | 4.05 |
| **2022** | 63.14 | 30.70 | 99.64 | 8.27 |
| **Average** | **73.48** | **21.35** | **56.18*** | **4.30** |

* Average excludes reported emissions from 2018 and before because of different VOC emission factors.

As part of 2017 amendment to Rule 1118, staff increased the VOC emission factor based on EPA's updated AP-42 guidance by 10-fold (from 0.063 to 0.66 pound of VOC per million Btu). Therefore, reported VOC emissions after 2018 are different in order of magnitude from the level of VOC emissions reported in the prior years.

### *EMISSION REDUCTIONS*

PAR 1118 is expected to achieve emission reductions in all types of emissions ($SO_2$, VOC, and NOx) and to be aligned with AB 617 CERP actions through establishing the new $SO_2$ performance target of 0.25 ton per million barrels of processing capacity. The table below shows the expected reduction in different types of emissions from flares based on the adjusted level of emissions in 2017 which was established as the baseline year in AB 617 CERP for WCWLB community. Staff adjusted the level of emissions in 2017 based on the assumption that in any year that facilities $SO_2$ emissions exceeded the $SO_2$ performance target of 0.5 ton per million barrels of processing capacity, they paid mitigation fees and applied changes to their operations, practices, or equipment to achieve this performance target (i.e., 0.5 ton of $SO_2$ emissions per million barrels of processing capacity). So, for the baseline emissions in 2017, if any facility had $SO_2$ emissions beyond the corresponding level to $SO_2$ performance target of 0.5 ton per million barrels of processing capacity, staff adjusted the emissions to that lower level. The listed values for emission reductions are the average ~~expected~~ reductions for each type of pollutant compared to the adjusted emission level in 2017 (AB 617 CERP baseline year) ~~based on~~ that are expected to be achieved as a result of staff's new proposal to lower the $SO_2$ performance target from 0.5 ton per million barrels of processing capacity to the proposed annual $SO_2$ performance target of 0.25 ton per million barrels of processing capacity.

**Table 5-2. Estimated Emission Reductions[a] at Proposed Annual $SO_2$ Performance Target of 0.25 ton/MMbbl**

| Pollutant Type | All Facilities | | Wilmington, Carson, West Long Beach Facilities | | |
|---|---|---|---|---|---|
| | Ton per Year | Percent | Ton per Year | Percent | CERP Emission Reductions Target (tpy) by 2030 |
| **$SO_2$** | 16.6 | 30 | 13.8 | 51[b] | 11 |
| **VOC** | ~~3.3~~3.8 | ~~16~~18 | ~~3.3~~3.8 | ~~20~~23[c] | 1 |
| **NOx** | 10.1 | 69 | 9.8 | 89[d] | 19 |

[a] Emission reductions are calculated based on emissions level in 2017 (AB 617 CERP baseline year), except for VOC for which values are calculated based on emissions level in 2019 due to updated emission factor for VOC in effect since 2019.

[b] CERP's goal of achieving a minimum of 50 percent $SO_2$ emission reductions from refineries by 2030 is expected to be achieved through Rule 1118.

[c] CERP's goal of achieving a minimum of 50 percent VOCs emission reductions from refineries by 2030 is expected to be achieved through Rules 1178, 1118, and/or 1173.

[d] CERP's goal of achieving a minimum of 50 percent NOx emission reductions from refineries by 2030 is expected to be achieved primarily through Rule 1109.1 and partially through Rule 1118.

Reductions in $SO_2$ and VOCs emissions in WCWLB community are expected to exceed CERP emission reductions objectives for flaring at refineries by 2030. NOx emission reductions from refinery flares in WCWLB community is estimated to be less than the corresponding CERP emission reductions target; however, the CERP's objective of achieving a minimum of 50 percent NOx emission reductions from refineries is expected to be achieved primarily through Rule 1109.1 and partially through Rule 1118. NOx emission reductions from refinery equipment at WCWLB community subject to Rule 1109.1 is estimated to be 1,095-1,460 tons per year by 2030. At full implementation, Rule 1109.1 is expected to achieve 1,643 tons per year of NOx emission reductions from refineries located at WCWLB community, which far exceeds the expected 19 tons per year emissions reduction objective. The implementation schedule for the NOx emission reductions expands beyond the 2030 CERP objective; however, the implementation schedule is designed to achieve approximately 75% of the required reductions by 2027 and approximately 90% of the required reductions by 2031 more than satisfying the CERP objective.

*Implication for Particulate Matters Emission Reductions*

South Coast AQMD has continued to adopt and implement rules to reduce air pollution emissions and public exposure to unhealthful air pollution as we strive to achieve the National Ambient Air Quality Standards (NAAQS) for ground-level ozone and particulate matter. South Coast AQMD is in attainment for some of the NAAQS, include the $SO_2$ standard; however, $SO_2$ reductions are needed to attain the PM2.5 standards.

Several studies have found correlations between both short-term and long-term exposure to elevated ambient particulate matter levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks, chronic obstructive pulmonary disease exacerbation, combined respiratory-diseases and number of hospital admissions in different parts of the United States and in various areas around the world. Higher levels of PM2.5 have also been related to increased mortality due to cardiovascular or respiratory diseases, hospital admissions for acute respiratory conditions, school absences, lost workdays, a decrease in respiratory function in children, and increased medication use in children and adults with asthma.

Particulate matters originate from a variety of sources (stationary and mobile) and may be directly emitted in the atmosphere (primary emissions) or formed by transformation of other gaseous emissions that are directly emitted into the atmosphere (secondary emissions). In the latter case, such air pollutants are considered precursors to PM formation.

The higher PM2.5 concentrations in the South Coast Air Basin are mainly due to the secondary formation of smaller particulates resulting from precursor gas emissions (i.e., NOx, $SO_2$, ammonia, and VOC) that are converted to PM in the atmosphere. The precursors are from mobile, stationary, and area sources, with the largest portion resulting from fuel combustion. Control measures that reduce PM precursor emissions have a beneficial impact on ambient PM levels. It is sometimes difficult to quantify the contribution of precursors to secondary PM2.5 formation since many of the formed products can fluctuate between the particulate and vapor states depending on conditions. The degree to which these precursors react to form PM2.5 depends on environmental conditions (temperature and humidity) and various drivers for complex chemical reactions. Staff estimates a ratio of 5:1 to convert $SO_2$ emission reductions to PM2.5 reductions; therefore, the $SO_2$ emission reductions in PAR 1118 is estimated to result in approximately 3.32 tons of PM2.5 emission reductions per year.

### ***COST-EFFECTIVENESS***

Health and Safety Code Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. South Coast AQMD routinely conducts cost-effectiveness analyses regarding proposed rules and regulations that result in the reduction of criteria pollutants (NOx, $SO_2$, VOC, PM, and CO). PAR 1118 does not establish BARCT requirements; however, staff conducted a cost-effectiveness analysis of the proposed annual throughput threshold to control NOx emissions from LPG flares, as presented in the table below.

The cost-effectiveness of a control technology is measured in terms of the control cost in dollars per ton of air pollutant reduced for each class and category of equipment. The costs for the control technology include purchasing, installation, operating, and maintaining the control technology. South Coast AQMD typically relies on the Discounted Cash Flow (DCF) method which converts all costs, including initial capital investments and costs expected to be incurred in the present and all future years of equipment life, to a present value. The final cost-effectiveness measure is derived by dividing the present value of total costs by the total emissions reduced over the equipment life of 25 years.

Staff calculated the minimum annual throughput at which LPG recovery was cost-effective to have a total heat content (based on higher heating value) equal to 15,000 MMBtu per year. Cost-effectiveness was calculated to be $58,000 per ton of NOx reduced over the lifetime of the auxiliary gas refrigeration/compressor system which is well below the cost-effectiveness threshold of $349,000 (adjusted for CPI) per ton of NOx reduced as established by 2022 AQMP. The annual throughput of 15,000 MMBtu per year or greater is below the cost-effectiveness threshold of $349,000 (adjusted for CPI) per ton of NOx reduced.

***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, carbon monoxide, sulfur oxides, oxides of nitrogen, and their precursors. Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option.

Staff evaluated the cost-effectiveness of reducing the throughput threshold beyond the proposed threshold of 15,000 MMBtu per year to a lower threshold of 3,500 MMBtu per year. The lower threshold would require all three refineries that operate a non-hydrogen clean service flare (LPG flare) to install a larger refrigeration/chiller system regardless of whether a new flare was installed. Staff estimates that the new larger refrigeration/chiller system will need to be twice as large with an estimated cost of approximately $21 MM. The larger system will also require approximately double the electricity usage since a larger compressor will be necessary. This increase in operating cost will negate any potential profit from recovery of the LPG when compared to the cost savings associated with the proposed 15,000 MMBtu per year threshold. Furthermore, since one facility currently recovers nearly all of the LPG, the incremental emission reductions from that the facility is low. The annual throughput of 3,500 MMBtu/year has an incremental cost-effectiveness of $16 MM and low incremental emission reductions of 0.006 ton per year for all three facilities. The table below summarizes both the cost-effectiveness and incremental cost-effectiveness assessment.

**Table 5-3. Cost-Effectiveness and Incremental Cost-Effectiveness Analysis for LPG Flares**

| Equipment Type | Cost-Effectiveness at 15,000 MMBtu/yr | Incremental Cost-Effectiveness at 3,500 MMBtu/yr |
|---|---|---|
| **LPG Flare** | $58,000 per ton of NOx reduced | $16 MM per ton of NOx reduced |

### *ANTICIPATED SCHEDULE FOR EMISSION REDUCTIONS*

The $SO_2$ performance target of 0.5 ton per million barrels of processing capacity remains effective upon rule adoption and the owners or operators of facilities are required to meet this target when reporting their $SO_2$ emissions for calendar years 2024 and 2025. The $SO_2$ performance target of 0.35 ton per million barrels of processing capacity becomes effective for reporting $SO_2$ emissions for calendar years 2026 to 2028 and is expected to achieve 9.3 tons of $SO_2$ emission reductions per year in average with respect to baseline year emissions (i.e., 2017). The $SO_2$ performance target of 0.25 ton per million barrels of processing capacity becomes effective for reporting $SO_2$ emissions for calendar year 2029 and after and is expected to achieve an extra 7.3 tons of $SO_2$ emission reductions per year in average, i.e., an average of 16.6 tons of $SO_2$ per year in total. The table below shows the schedule for expected emission reductions under PAR 1118 in all types of emissions associated with flaring. The presented emission reductions are the average expected emission reductions for each type of pollutant compared to the emission level in 2017 (AB 617 CERP baseline year) based on the corresponding proposed annual $SO_2$ performance target.

**Table 5-4. PAR 1118 Estimated Emission Reductions and Schedule***

| Pollutant Type | Calendar Year 2026 | | Calendar Year 2029 and after | |
|---|---|---|---|---|
| | Ton per Year | Percent | Ton per Year | Percent |
| **$SO_2$** | 9.3 | 17 | 16.6 | 30 |
| **VOC** | 1.9 | 9 | ~~3.3~~<u>3.8</u> | 16 |
| **NOx** | 1.2 | 8 | 10.1 | 69 |

* Emission reductions are calculated from emissions occurring during the baseline year 2017 as established in the AB 617 CERP for WCWLB community.

### *SOCIOECONOMIC IMPACT ASSESSMENT*

On March 17, 1989, the 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 Sections 40440.8 and 40728.5 require a socioeconomic impact assessment for proposed and amended rules resulting in significant impacts to air quality or emission limitations. Thus, this Socioeconomic Impact Assessment has been prepared in accordance with Health and Safety Code and the South Coast AQMD Governing Board requirements. The type of industries or businesses affected, the range of probable costs, and the cost-effectiveness of alternatives to air pollution control equipment and methods, to the extent quantifiable and data is available, are addressed below. Additional information and analysis on the availability and cost-effectiveness of alternatives, discussion of potential emission reductions, and the necessity of amending the rule are included elsewhere in this report.

*Background*

PAR 1118 is the second phase of the planned two-phase rule amendment which seeks to achieve further emission reductions from refinery and refinery-related flares. Specifically, PAR 1118 would establish a lower annual $SO_2$ performance target for all flares, new annual NOx performance target for hydrogen clean service flares, a throughput threshold with total heat content of 15,000 MMBtu per year (based on total flared gas higher heating value) for LPG clean service flares and requires the installation of continuous flow meters (CFMs) for hydrogen clean service flares. PAR 1118 also updates and establishes requirements for notifications and flare event data reporting using FENS for affected facilities.

*Affected Facilities and Industries*

PAR 1118 is applicable to 12 facilities operating 31 flares (two ground flares and 29 elevated flares) located within Los Angeles County. Eight out of the 12 facilities are classified as petroleum refineries by the North American Industrial Classification System (NAICS 324110), three facilities are hydrogen production plants classified as industrial gas manufacturers (NAICS 325120), and the remaining facility is a sulfur recovery plant classified as a basic inorganic chemical manufacturer (NAICS 325180). Of the 31 flares, three are LPG clean service flares operating at three petroleum refineries, four are hydrogen clean service flares operating across three hydrogen production plants and one petroleum refinery, and the remaining 24 are general service flares operating at eight petroleum refineries and the sulfur recovery plant. Only five of the facilities subject to PAR 1118 are anticipated to incur compliance costs; their parent companies do not meet the definitions of a small business pursuant to South Coast AQMD Rule 102 – Definition of Terms, the South Coast AQMD Small Business Assistance Office, or the 1990 federal Clean Air Act Amendments.

*Methods of Compliance and Associated Compliance Costs*

Facilities affected by the throughput threshold in PAR 1118 can pursue different strategies to comply with rule requirements. Specifically, these facilities are anticipated to install either a refrigeration/chiller system or a new flare to replace the existing flare in order to recover LPG stream and minimize the amount of gas stream that is sent to the flare. Also, PAR 1118 requires replacement of "on/off" flow meters with CFMs. The following sections discuss~~es~~ the anticipated costs associated with each of these control measures, presented in 2023 dollars.

*Refrigeration/Chiller System*

A refrigeration/chiller system is one option a facility may install to minimize or eliminate combusting LPG. The refrigeration/chiller system allows the facility to recover the LPG that would otherwise be burned at the existing LPG clean service flare. LPG is a mix of propane and butane, of which the majority is propane.

The total one-time capital cost for a refrigeration/chiller system is estimated to be $11.2 MM, which includes estimated costs for major equipment, electrical upgrades, installation, and engineering. The annual operating and maintenance cost associated with providing electricity to the refrigeration/chiller system is estimated to be $176,000 per year based on an assumed 0.18

cents per kilowatt-hour (kWh)[9] for industrial electricity rates and 981,000 kWh of annual electricity demand. However, the recovered LPG can be sold to generate additional revenue to offset the annual electricity cost. The revenue from the recovery and sale of LPG is estimated to be $392,000 per year, based on a propane spot price of 71 cents per gallon[10] as of September 27, 2023, and an assumed 65,000 standard cubic feet per day of recovered LPG. The net savings from the sale of LPG after subtracting the annual electricity cost is approximately $216,000 per year.

*Replacement of an Existing Flare with New Flare*

A representative of one petroleum refinery operating a LPG clean service flare indicated that reported annual throughput for their LPG flares is primarily derived from the use of LPG as purge gas, since their current LPG flare design requires higher levels of purge gas to maintain a positive flow in the flare and to prevent explosions. Thus, this facility may elect to install a new LPG flare that requires lower levels of purge gas in lieu of installing a refrigeration/chiller system for their existing LPG flare, allowing the saved purge gas to be sold instead. The total one-time capital cost for a new LPG clean service flare system is estimated to be $10 MM, which includes cost estimates for major new elevated flare equipment, ignition system, utility piping and wiring for pilot gas, a structural base, installation, and engineering. A new LPG clean service flare system would not have additional annual operating and maintenance costs relative to the existing LPG clean service flare. However, similar to the refrigeration/chiller system, the new LPG flare system will result in less LPG flared and additional LPG which can be sold, resulting in additional revenue up to $392,000 per year offsetting some of the annualized capital costs.

*Continuous Flow Meter*

Facilities operating hydrogen clean service flares are anticipated to replace their existing “on/off” flow meters with CFMs. The one-time capital cost and the one-time installation cost for a new CFM are each estimated to be $200,000, which brings the total installed cost to $400,000. Once installed, the new CFMs do not require incremental operation and maintenance costs.

*Permits*

Facilities installing either a refrigeration/chiller system or a new flare to meet the throughput threshold will be required to submit a permit application for construction and operation with fees expected to range between $5,000 and $10,000. This analysis assumes a one-time permit fee of $10,000 per facility. Construction and operation permits are not required for the installation of CFMs at the hydrogen production facilities.

*Flare Minimization Reduction Plan (FMRP) Modification Fees*

Installation of CFMs, a refrigeration/chiller, or a new flare will require revisions to the existing FMRPs by the facilities. The fee to modify an FMRP is approximately $4,000.

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9 California Energy Commission, 2022 Integrated Energy Policy Update, Docket 22-IEPR-03 – Electricity Forecast, CEDU Baseline Forecast – LADWP, https://efiling.energy.ca.gov/GetDocument.aspx?tn=248381&DocumentContentId=82804, accessed February 27, 2024.

10 U.S. Energy Information Administration –EIA –Independent Statistics and Analysis, Sources and Uses, Petroleum and Other Liquids, Data, Prices – Daily Spot Prices, Propane – Mount Belvieu, Texas – 1992-2024, , propane price accessed on September 27, 2023. https://www.eia.gov/dnav/pet/hist/EER_EPLLPA_PF4_Y44MB_DPGD.htm

### *Average Annual Compliance Cost*

The owner or operator of an LPG flare is required to submit a permit application for any LPG flare that has exceeded the proposed annual throughput level in any two consecutive years since 2017. For the three facilities impacted by the throughput threshold, one facility already has equipment installed and the LPG flare meets the proposed annual throughput threshold; thus, it will not incur additional compliance costs. Three out of the four hydrogen clean service flares have existing “on/off” flow meters which will need to be replaced with CFMs; one hydrogen production plant already has a CFM installed and thus, will not incur additional cost.

Facilities operating flares subject to the lower annual $SO_2$ performance target and facilities operating hydrogen clean service flares subject to the new annual NOx performance target may obtain further results in minimizing flare emissions by setting up and implementing FMPs which does not require adding new control equipment and primarily relies on a reevaluation of existing process and equipment operating procedures or practices. Based on several site visits to facilities, most have indicated a majority of the changes in recent years were the direct result of operational practices and procedures at the facilities. Over the years, many facilities have reduced flaring emissions through operational changes, including slowing down the shutdown process, modernization of equipment, along with proper maintenance and inspection, which leads to increased reliability of process equipment, and renting thermal oxidizers to combust excess gases during scheduled shutdown and subsequent startup operations. However, these process or operational changes are specific to each facility which cannot be quantified at this time. A performance target provides the facility with an inherent flexibility to pursue the most cost-effective options available to that facility specifically and does not require prescriptive controls, therefore having no quantifiable compliance costs.

In total, only five of the 12 affected facilities are anticipated to incur compliance costs as a result of PAR 1118, as follows: 1) two petroleum refineries with LPG flares which currently do not meet the throughput threshold; and 2) three hydrogen production plants which do not meet the reporting requirements.

The cost estimates of implementing PAR 1118 over the period from 2025 to 2052 take into consideration the following items:

1) Payment of construction/operation permit fees for two facilities in 2025;
2) FMRP application fees for five facilities in 2025;
3) Installation of three CFMs at three facilities in 2025;
4) Installation of one refrigeration/chiller at one facility and the installation of a new flare system at one facility, both beginning in 2027;
5) Construction period of 18 to 24 months; and
6) Equipment lifetime of 25 years for the refrigeration/chiller and new flare system.

The total average annual compliance cost of PAR 1118 is estimated to range from $381,677 to $722,904 for a 1% and 4% interest rate, respectively. The following table presents a summary of the average annual cost of PAR 1118 by cost or savings category.

**Table 5-5. Average Annual Cost by Category**

| Average Annual Cost of PAR 1118 (2025-2052) | | |
|---|---|---|
| **Cost Categories** | **1% Interest Rate** | **4% Interest Rate** |
| **Capital Costs** | | |
| Refrigeration System | $108,389 | $148,394 |
| Installation - Refrigeration System | $130,067 | $178,072 |
| Engineering - Refrigeration System | $130,067 | $178,072 |
| Electrical Upgrades - Refrigeration System | $89,709 | $122,819 |
| New Flare | $131,018 | $179,374 |
| Installation - New Flare | $157,222 | $215,249 |
| Engineering - New Flare | $122,829 | $168,163 |
| Construction and Operation Permit | $482 | $659 |
| Continuous Flow Meter | $26,974 | $36,930 |
| Installation - Continuous Flow Meter | $26,974 | $36,930 |
| FMRP Revision Application Fee | $803 | $1,099 |
| **Recurring Costs** | | |
| Electricity - Refrigeration System | $157,143 | $157,143 |
| **Recurring Costs Savings** | | |
| Sales from LPG | ($700,000) | ($700,000) |
| **Total** | **$381,677** | **$722,904** |

*Macroeconomic Impacts on the Regional Economy*

Regional Economic Models, Inc (REMI) developed the Policy Insight Plus Model, which is a tool that South Coast AQMD typically uses to assess the impacts of rule development projects on the job market, prices, and other macroeconomic variables in the region. However, when the average annual compliance cost of a project is less than one million current U.S. dollars, the model cannot reliably determine the macroeconomic impacts, because resultant impacts from the project would be too small relative to the baseline economic forecast.

Since the total annual compliance cost of PAR 1118 is estimated at $381,677 to $722,904 for a 1% and 4% interest rate, respectively, which is well below $1 MM threshold, a macroeconomic impact analysis was not conducted for PAR 1118.

### *CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS*

Pursuant to the California Environmental Quality Act (CEQA) Guidelines Sections 15002(k) and 15061, the proposed project (PAR 1118) 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*

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 staff report.

*Necessity*

Proposed Amended Rule 1118 is needed to reduce emissions from flares operated at petroleum refineries and related operations to satisfy the commitment in the resolution from the 2017 amendment of Rule 1118 and to achieve the goals that were set forth by the AB 617 CERP for WCWLB community.

*Authority*

The South Coast AQMD Governing Board has authority to adopt amendments to Rule 1118 pursuant to Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, and 41508.

*Clarity*

Proposed Amended Rule 1118 is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

*Consistency*

Proposed Amended Rule 1118 is in harmony with the U.S. EPA's Refinery Sector Rule, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

*Non-Duplication*

Proposed Amended Rule 1118 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 drafting Proposed Amended Rule 1118, the following statutes which South Coast AQMD hereby implements, interprets, or makes specific are referenced: Assembly Bill 617, Health and Safety Code Sections 39002, 40000, 40001, 40702, 40440(a), 40440(b), 40440(c), 40725 through 40728.5, and 41508.

### COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, South Coast AQMD is required to perform a comparative 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 combustion equipment subject to PAR 1118. The comparative analysis for PAR 1118 can be found in the following table~~ below~~.

**Table 5-6. Comparative Analysis for PAR 1118 with U.S. EPA Refinery Sector Rule**

| Rule Element | PAR 1118 | U.S. EPA Refinery Sector Rule (2015) |
|---|---|---|
| **Applicability** | Flares used at Refineries, Sulfur Recovery Plants, and Hydrogen Production Plants | Petroleum refining process units and related emissions points that are (1) located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act; and (2) emit or have equipment containing or contacting one or more of the hazardous air pollutants as listed in Table 1 of Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.<br><br>This applicability includes all miscellaneous process vents from petroleum refining process units defined as a gas stream containing greater than 20 parts per million by volume organic hazardous air pollutants (HAP) that is continuously or periodically discharged from a petroleum refining process unit; including gas streams that are routed to a control device prior to discharge to the atmosphere; not to include hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated when the hydrogen plant is degassed or de-aerated. |
| **Requirements** | • Requirements for owners or operators of facilities to prepare and submit flare minimization plans and pay mitigation fees upon exceeding $SO_2$ or NOx performance targets, to include any specific change to Facility policies and procedures to be implemented and any equipment improvements to minimize flaring and Flare emissions and comply with the applicable Performance Target(s) for:<br>o Turnarounds and other scheduled maintenance;<br>o Essential Operational Needs and the technical reason for which the Vent Gas cannot be prevented from being flared during each specific situation; and<br>o Emergencies, including procedures that will be used to prevent recurring equipment breakdowns and process upsets.<br>• Requirements for owners or operators of LPG flares to prepare and submit flare minimization plans upon exceeding the annual throughput limit, to include all specific procedure changes to be implemented by the facility to meet the applicable annual | • **Emergency flaring provisions**<br>The owner or operator of a flare that has the potential to operate above its smokeless capacity under any circumstance shall:<br>o Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases<br>o The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator alters the design smokeless capacity of the flare |

| Rule Element | PAR 1118 | U.S. EPA Refinery Sector Rule (2015) |
|---|---|---|
| | throughput threshold, the list of corrective action(s), and schedule to implement the action(s)<br>• Flare tip velocity is to be calculated as specified in Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries<br>• Maximum flare tip velocity to be calculated as specified 40 CFR Part 63 Subpart CC<br>• Addressed during 2017 amendment to Rule 1118: Net heating value of the Flare combustion zone gas to be calculated as specified 40 CFR Part 63 Subpart CC<br>• Requirements to conduct a single Specific Cause Analysis for specific flare events, aligned with 40 CFR Part 63 Subpart CC<br>• Requirements to record and conduct a single specific cause analysis report for specific flare events, aligned with 40 CFR Part 63 Subpart CC | |
| **Reporting** | - | - |
| **Monitoring** | • Reference to 40 CFR Part 63 Subpart CC for flare monitoring system requirements<br>• Previous amendment: Requirement to install, operate, calibrate, maintain, and record data from any monitoring systems required by 40 CFR Part 63 Subpart CC for all general service flare | |
| **Record Keeping** | - | - |

**Table 5-7. Comparative Analysis for PAR 1118 with Other Rules**

| Rule Element | PAR 1118 | SJVAPCD Rule 4311 | Bay Area AQMD Regulation 12 Rule 11 | Bay Area AQMD Regulation 12 Rule 12 |
|---|---|---|---|---|
| **Applicability** | Flares used at Refineries, Sulfur Recovery Plants, and Hydrogen Production Plants | Applicable to operations involving the use of flares including oil and gas production facilities, sewage treatment plants, waste incineration and petroleum refining operations | Applicable to flares located at refineries; for the purpose of monitoring and recording flare emission data | Applicable to flares located at refineries |
| **Requirements** | • Requirements to conduct a single Specific Cause Analysis for specific flare events<br>• Requirements to record and conduct a single specific cause analysis report for specific flare events<br>• $SO_2$ performance target of 0.35 ton per million barrels of processing capacity for reporting emissions for calendar year 2026 to 2028<br>• Requirements for owners or operators of facilities to meet $SO_2$ performance target of 0.25 ton per million barrels of processing capacity for reporting emissions for calendar year 2029 and afterward<br>• Requirements for owners or operators of hydrogen production plants to meet NOx performance target of 0.3 pound per million standard cubic feet of hydrogen production capacity for reporting emissions for calendar year 2025 and afterward | • Ground-level Enclosed Flares:<br>NOx Emission Limits<br>(Without Steam Assist)<br>o <10 MMBTU – 0.09512 lb/MMBtu<br>o 10-100 MMBtu – 0.1330 lb/MMBtu<br>o >100 MMBtu – 0.5240 lb/MMBtu<br>(With Steam Assist)<br>o All – 0.068 lb/MMBtu<br>• Flare Annual Throughout Threshold - 25,000 MMBtu per year for flares at oil and gas operations or chemical operations<br>• NOx Emissions Limits - 0.018 (lb/MMBtu) for new or modified enclosed flares at oil and gas operations or chemical operations<br>• Updated Flare Minimization Plan required every five years if flare at refinery has a flaring capacity of greater than or equal to 5.0 MMBtu per hour<br>• Petroleum refinery $SO_2$ Performance Target – 0.50 ton per million barrels of crude processing capacity | - | • Flaring is prohibited unless it is consistent with an approved Flare Minimization Plan and all commitments due under that plan have been met<br>• Requirements for FMP to be updated no more than 12 months following approval of the original FMP and annually thereafter<br>o The owner or operator of a flare shall review the FMP and revise the plan to incorporate any new prevention measures identified<br>o The updates must be approved and signed by a Responsible Manager<br>o Annual FMP updates (with exception of confidential information) shall be made available to the public for 30 days. The Air Pollution Control Officer shall consider any written comments received during this period prior to approving or disapproving the update |

| Rule Element | PAR 1118 | SJVAPCD Rule 4311 | Bay Area AQMD Regulation 12 Rule 11 | Bay Area AQMD Regulation 12 Rule 12 |
|---|---|---|---|---|
| | • Requirements for owners or operators of facilities to prepare and submit flare minimization plans and pay mitigation fees upon exceeding $SO_2$ or NOx performance targets<br>• Requirements for non-hydrogen clean service (LPG) flares to meet and maintain an annual throughput level with total heat content of 15,000 MMBtu per year (based on higher heating value)<br>• Requirements for owners or operators of LPG flares to prepare and submit flare minimization plans upon exceeding the annual throughput limit | | | |
| **Reporting** | • Requirement to report the relative cause in the quarterly reports<br>• Requirements for owners or operators to report $SO_2$ and NOx emissions, and annual throughput of non-hydrogen clean service (LPG) flares, as applicable, for any calendar year where the applicable threshold was exceeded<br>• Requirements for the owners or operators of facilities to submit monthly reports of flare vents data in an electronic format<br>• Requirements for the owners or operators of facilities to submit | • Requirement for annual report summarizing reportable flaring event containing the results of an investigation to determine primary cause and factors of the flaring event, prevention measures considered or implemented, and the date, time, and duration of the flaring event<br>• Requirement for any flare at a major source that has a flaring capacity equal to or greater than 50 MMBtu per hour to report periods of flare monitoring system downtime greater than 24 continuous hours by the following working day | • Requirement for owner or operator of a flare to submit a monthly report to the Air Pollution Control Officer on or before 30 days after the end of each month<br>• For any 24-hour period during which more than one million standard cubic feet of vent gas was flared, a description of the flaring including the cause, time of occurrence and duration, the source or equipment from which the vent gas originated, and | - |

| Rule Element | PAR 1118 | SJVAPCD Rule 4311 | Bay Area AQMD Regulation 12 Rule 11 | Bay Area AQMD Regulation 12 Rule 12 |
|---|---|---|---|---|
| | specific cause analysis report in an electronic format<br>• Requirement for the owner or operator of a facility with no processing capacity, that is publicly available, to report their processing capacity to the Executive Officer within 30 days of the end of every calendar year<br>• Requirements for flare event notifications to be provided by owners or operators of facilities through FENS<br>• Requirements for data substitution for flare events with monitored data not measured or recorded for a period of time less than or equal to 15 consecutive minutes | • Requirement for the operator of a flare subject to flare minimization plans to submit an annual report to the Air Pollution Control Officer that summarizes all Reportable Flaring Events that occurred during the previous 12-month period within 30 days following the end of the previous calendar year | any measures taken to reduce or eliminate flaring<br>• Requirements for owner or operator of a flare to submit a flow verification report to the Air Pollution Control Officer every six months in the monthly report | |
| **Monitoring** | • Requirements for replacing of any on/off flow meters with cfm meters for general service flares and hydrogen clean service flares<br>• Allowance for monitoring systems calibrations to be postponed up to 72 hours when there is an ongoing flare event | • Requirement for a refinery flare that has a flaring capacity equal to or greater than 50 MMBtu per hour to monitor vent gas composition using one of the five methods approved<br>• Requirement for any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour to monitor volumetric flows of purge and pilot gases with flow measuring devices | • Requirements for the owner or operator to continuously monitor vent gas to the flare for volumetric flow with an approved device<br>• Requirements for the owner or operator to monitor vent gas composition by sampling, integrated sampling or continuous monitoring | - |
| **Record Keeping** | • Requirement to retain the records of the relative cause analysis | • Requirement for records to be maintained for a minimum of five years on-site:<br>o Compliance determination | • Requirement for all in-line continuous analyzer and flow monitoring data to be | - |

| Rule Element | PAR 1118 | SJVAPCD Rule 4311 | Bay Area AQMD Regulation 12 Rule 11 | Bay Area AQMD Regulation 12 Rule 12 |
|---|---|---|---|---|
| | | o Source testing results<br>o For emergencies, duration of flare operation, amount of gas burned, and nature of emergency<br>o Approved Flare Minimization Plan<br>o Annual Reports<br>o Monitoring data collected | continuously recorded as one-minute averages | |
| **Exemptions** | • Added the exemption for owner or operator of a facility from including sulfur dioxide emissions, NOx emissions, visible emissions that exceed the applicable limits, or flare tip velocity that exceeds the applicable limit from flare events caused by **<u>external water curtailment</u>** beyond the operator's control (excluding interruptible service agreements) from:<br>o The applicable performance target, if documentation is provided that proves the existence of such events and it is certified in writing by the facility official responsible for emission reporting; and<br>o The smokeless capacity prohibitions<br>• Similar considerations for annual throughput | • Flares that combust only propane or butane or a combination of propane and butane | • Limited exemptions to total hydrocarbon and methane composition monitoring and reporting | - |

# APPENDIX A: COMMENTS AND RESPONSES

### *PUBLIC WORKSHOP COMMENTS*

Staff held a Public Workshop on February 8, 2024, to provide a summary of proposed amendments to Rule 1118. The following is a summary of the verbal comments received on PAR 1118 and staff's responses.

*Commenter #1: Julia May – Communities for a Better Environment (CBE)*

Ms. Julia May commented that the rule should have more stringent requirements including a lower $SO_2$ performance target and a new VOC performance, because some flare events have high VOC emissions without high levels of $SO_2$ emissions. Ms. May also did not agree with the industry's security concern regarding the flare video requirement and requested staff maintain the requirement for refineries to make the flare images publicly available.

**Staff Response to Commentor #1:**

Staff responded by committing to reviewing the data regarding flare events with high VOC emissions. See response to comment letter #3 for further details.

## COMMENT LETTERS

### Comment Letter #1

WSPA

**Ramine Ross**
Senior Manager, Southern California Region

February 21, 2024

Heather Farr
Planning and Rules Manager
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Via e-mail at: hfarr@aqmd.gov

***Re: SCAQMD Proposed Amended Rule 1118, Control of Emissions from Refinery Flares***
***WSPA Comments on Preliminary Draft Rule Language***

Dear Ms. Farr,

Western States Petroleum Association (WSPA) appreciates the opportunity to participate in South Coast Air Quality Management District (SCAQMD or District) Proposed Amended Rule 1118, Control of Emissions from Refinery Flares (PAR1118). The stated purpose of this rulemaking is to align Rule 1118 with items listed in the Community Emissions Reduction Plan (CERP) for the Wilmington, Carson, West Long Beach Assembly Bill 617 (AB617) community.[1] In 2019, SCAQMD issued that CERP with several emission reduction goals, including a proposal for lower emissions performance targets under Rule 1118.[2]

WSPA is a non-profit trade association representing companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas, renewable fuels, and other energy supplies in five western states including California. WSPA has been an active participant in air quality planning issues for over 30 years. WSPA member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the SCAQMD and thus will be impacted by PAR1118.

SCAQMD published the Preliminary Draft Rule Language and Preliminary Draft Staff Report on January 19, 2024.[3,4] WSPA offers the following comments.

[1] SCAQMD PAR 1118 Working Group Meeting #2. Available at: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118/par-1118-wgm-2-presentation.pdf?sfvrsn=8.
[2] Community Emissions Reduction Plan, Wilmington, Carson, West Long Beach, September 2019. Available at: https://www.aqmd.gov/docs/default-source/ab-617-ab-134/steering-committees/wilmington/cerp/final-cerp-wcwlb.pdf?sfvrsn=8.
[3] SCAQMD PAR 1118 Preliminary Draft Rule Language. Available at: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118/par-1118---preliminary-draft-rule-language-20240119.pdf?sfvrsn=12.
[4] SCAQMD PAR 1119 Preliminary Draft Staff Report. Available at: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118/par-1118---preliminary-draft-staff-report-20240119.pdf?sfvrsn=12.

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Page 2

1. **PAR1118 proposes new performance targets for sulfur dioxide ($SO_2$) without having provided sufficient technical foundation nor an evaluation of cost-effectiveness. WSPA requests SCAQMD provide stakeholders with these demonstrations before Governing Board consideration of the proposed rule.** 1-1

PAR1118(f)(1) proposes to update the $SO_2$ "performance targets" as follows:

| Table 1: Performance Target Schedule for Sulfur Dioxide | |
|---|---|
| $SO_2$ Performance Target | Effective Date |
| 0.5 | Calendar Year 2024 |
| 0.35 | Calendar Year 2026 |
| 0.25 | Calendar Year 2028 and after |

In the Wilmington, Carson, West Long Beach CERP, the District included a goal to lower performance targets and/or increase mitigation fees, with a goal to reduce flaring events and/or emissions by 50%, if feasible.[5] At the time of CERP development and adoption, the District did not present a technical basis for these reduction goals. Rather, the District noted that "…emission reduction goals are subject to future assessments and regulatory analyses."[6]

To date, SCAQMD has not demonstrated the technical basis for the proposed $SO_2$ performance target. As shown in Tables 2-5 and 2-6 of the staff report, Southern California refineries are already implementing many/most of the identified control measures for reducing emissions from planned and unplanned flare events.[7]

While it may not prescribe a specific equipment or technology outcome, the performance standard contemplates control measures which, in the aggregate, can be implemented by facilities to meet that standard. The Preliminary Draft Staff Report discusses a number of possible measures to reducing flare emissions,[8] but the District acknowledges that many/most of these measures have already been implemented or are not cost effective. For the remaining measures, Staff have not provided an estimate of their emissions reduction potential, and whether those measures could, in the aggregate, deliver sufficient emission reductions for facilities to meet the proposed performance targets.

In the staff report,[9] SCAQMD notes that facilities which are unable to meet the $SO_2$ performance targets will pay mitigation fees into a mitigation fund.

> *"All flare emissions, except for those caused by external power curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters or acts*

[5] Community Emissions Reduction Plan, Wilmington, Carson, West Long Beach, September 2019. Available at: https://www.aqmd.gov/docs/default-source/ab-617-ab-134/steering-committees/wilmington/cerp/final-cerp-wcwlb.pdf?sfvrsn=8.
[6] Ibid.
[7] SCAQMD PAR 1118 Preliminary Draft Staff Report. Available at: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118/par-1118---preliminary-draft-staff-report-20240119.pdf?sfvrsn=12.
[8] SCAQMD, PAR 1118 Preliminary Draft Staff Report, Table 2-5.
[9] SCAQMD, PAR 1118 Preliminary Draft Staff Report, page 3-4.

*of war or terrorism, are subject to this mitigation fee if a facility's $SO_2$ emissions exceed the $SO_2$ performance target."* Cont'd 1-1

While the mitigation fees may provide an alternative to complying with the proposed performance standards, those fees are not likely to reduce emissions from refinery flares. As noted in the staff report:[10]

> *"This mitigation fund…can only be spent with authorization from the South Coast AQMD Governing Board. Historically, mitigation fees have been used for certain emission reduction incentive programs, such as port of Long Beach zero-emission and hybrid terminal equipment deployment and demonstration project, zero-emission, and clean energy demonstration projects, etc. Programs for spending these mitigation fees are developed outside of this rule amendment process." [emphasis added]*

Therefore, the fees which would be imposed under PAR1118 for failing to meet the proposed performance standards will not reduce flaring emissions.

Before advancing this rule for Governing Board consideration, WSPA recommends that SCAQMD demonstrate that the proposal is both technically feasible for all covered equipment and cost-effective.

2. **PAR1118 provides effective dates for the updated sulfur dioxide ($SO_2$) performance targets. The timeline provided in the draft rule language is insufficient to implement flare minimization projects. WSPA recommends an extended timeline for the effective date for each performance target.** 1-2

In our previous comment letter, WSPA noted that performance target timelines must consider the time needed to prepare and obtain SCAQMD approval of a flare minimization plan and fully implement a flare minimization project. To this end, WSPA suggested a minimum of three years between each of the $SO_2$ performance target dates. With the January 19, 2024 version of the draft rule language, Staff updated the $SO_2$ performance target schedule to reflect 2 years between each of the target dates. WSPA is appreciative to Staff for the consideration of our earlier comment. WSPA does want to emphasize again that the recommendation for a 3-year window is based on the estimated time needed to complete flare minimization projects. For any capital project to reduce emissions from refinery flares, facilities would need at least three years to engineer and design, apply for, and be granted a permit to construct, and construct the project. WSPA strongly recommends that there be a minimum of three years between each of the $SO_2$ performance target milestones. Based on this recommendation, a suggested performance target schedule could have the 0.35 tons $SO_2$ per million barrels target effective in calendar year 2027, and the 0.25 tons $SO_2$ per million barrels target effective in calendar year 2030.

3. **PAR1118 would require facilities to use standard data substitution procedures for periods of invalid monitoring data if alternative substitution data has not been approved by SCAQMD within 12 months. This would result in a potentially inaccurate** 1-3

[10] Ibid.

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Page 4

**emission estimation and the imposition of higher fees for facilities. WSPA recommends that this requirement be removed from the draft rule language.** Cont'd 1-3

PAR1118(f)(4)(B) states:

> *(B) If there are any periods of invalid monitoring data within the calendar year, the owner or operator of the Facility shall:*
>
> *(i) Within 90 days following the end of the calendar year for which the Performance Target was exceeded, submit supporting data to demonstrate annual flare emissions, including any alternative data substitution pursuant to Attachment B: Guidelines for Emissions Calculations (Attachment B), for approval by the Executive Officer;*
>
> *(ii) If the alternative data substitution submitted pursuant to clause (f)(4)(B)(i) is not approved within 12 months of submittal, the standard data substitution procedures in Attachment B shall apply;*

PAR1118 would require facilities to use standard data substitution procedures for periods of invalid monitoring data if the alternative data substitution proposed by facilities has not been approved within 12 months. SCAQMD should be able to process documents required by rule conditions within a timely manner. The condition, as written, would result in facilities providing a potential over estimation of emissions and higher fees in the event SCAQMD has not been able to process the submitted data within the designated time period. Fees should be assessed based on the submitted data. Once the data has been processed by SCAQMD, if a higher fee is required, an adjustment can be made. WSPA requests that Section (f)(4)(B)(ii) be removed from the proposed rule language.

WSPA appreciates the opportunity to provide these comments related to PAR1118. We look forward to continued discussion of this important rulemaking. If you have any questions, please contact me at (310) 808-2146 or via e-mail at rross@wspa.org.

Sincerely,

Bamine Boos

Cc: Wayne Nastri, Executive Officer
Susan Nakamura, Chief Operating Officer
Sarah Rees, Deputy Executive Officer
Michael Krause, Assistant Deputy Executive Officer
Sarady Ka, Program Supervisor
Zoya Banan, Air Quality Specialist
SCAQMD Stationary Source Committee & Board Assistants

Western States Petroleum Association 970 West 190th Street, Suite 304, Torrance, CA 90502 310.808.2146 wspa.org

**Staff Response to Comment Letter #1:**

## Response to Comment 1-1:

Staff appreciates WSPA and its members taking the time to meet with staff to discuss concerns and submitting the comment letter. The technical basis for the proposed $SO_2$ performance target is staff's analysis of the scoping documents, facility site visits, and flaring data. Staff acknowledges that refineries have made important progress in reducing flaring and associated emissions since Rule 1118 was originally adopted. In addition to the controls already installed, refineries can obtain further reduction in the volume of vent gases routed to the flare by evaluating existing process and equipment operating procedures or practices. All of the facilities have demonstrated the proposed 0.25 ton of $SO_2$ per process capacity (MMbbl) can be achieved without the installation of additional control equipment; however, they are going to have to make process changes in order to be able to stay below the performance target on a consistent basis. Staff conducted several site visits to facilities, and most have indicated that a majority of the reduction in flaring emissions achieved, beyond the 2005 Rule 1118 requirement to install flare gas recovery systems, were the direct result of changes in operational practices and procedures at the facilities. One example of an important procedure being implemented is to improve equipment reliability with a more robust and frequent equipment inspection program and schedule. Facilities will likely work to stay below the performance target by implementing technically feasible options such as process, procedural, or operational changes specific to each facility, which cannot be quantified in terms of cost. Therefore, a cost-effectiveness analysis for the proposed $SO_2$ performance target of 0.25 ton per process capacity (MMbbl) was not completed for PAR 1118. Moreover, performance target is not the same as assessing the cost of a pollution control technology to establish a BARCT emission limits or imposing a control requirement such as a gas turbine cogeneration system.

A performance target provides each facility the flexibility to pursue the most cost-effective options available to that facility and does not require prescriptive controls that are able to be quantified. Moreover, each facility is unique in its operation, arrangement, physical layout, and space availability, so analyzing the availability or cost-effectiveness of alternatives, and identifying a range of probable costs, is not applicable to a target established by means of a proposed performance standard.

## Response to Comment 1-2:

Staff acknowledges that each refinery flare system can be complex and unique with opportunities for improvement. Furthermore, staff understands that if a facility decides that a capital project is the best route for flare minimization, time will be needed to complete and implement new projects. Staff has revised the effective date for the updated $SO_2$ performance target of 0.25 ton per process capacity (MMbbl) to 2029. The performance target schedule has been revised as listed in the following table.

| $SO_2$ Performance Target (Ton per Million Barrels) | Effective Date |
|---|---|
| 0.5 | Calendar Year 2024 to 2025 |
| 0.35 | Calendar Years 2026 to 2028 |
| 0.25 | Calendar Year 2029 and after |

## Response to Comment 1-3:

Staff understands the concern facilities may have regarding the use of standard data substitution procedures for invalid monitoring data if the alternative data has not been approved within 12 months of application submittal. Alternative data substitution evaluations can be a complex process that involves a significant amount of data analysis which can be time and labor intensive for the facility and the South Coast AQMD staff. Staff revised subparagraph (f)(4)(B) to remove the 12-month timeframe and included a provision or final written notification from the Executive Officer before the mitigation fees are to be paid. In addition, a process and timeframe for the facility to respond has been clarified. The facilities will now be required to submit the FMP and pay the mitigation fees within two months of receiving written notification from the Executive Officer regarding the approval or disapproval of the alternative substitution data.

## Comment Letter #2

Air Liquide

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
PLANNING AND RULES
21865 Copley Dr, Diamond Bar, CA 91765
**Zoya BANAN, PhD**

FEB 20, 2024

*Topic / Ref. : Proposed Amended Rule 1118 Comments*

Zoya,

Air Liquide appreciates the opportunity to comment on Proposed Amended Rule 1118, Control of Emissions from Refinery Flares. We particularly appreciate the cooperative process used to craft this rule which will lead to reduced emissions from flaring.

We urge the district to be mindful of the impact refinery rules have on non-refinery third parties which operate facilities that provide goods and services to a host refinery. Air Liquide operates a hydrogen production facility located within the Chevron USA El Segundo refinery. We are not nearly as heavily resourced as our host facility but are subject to the same rigorous standards and experience a disproportionate impact from the rules intended to reduce emissions and community health effects from refineries.

Paragraph (j)(10) creates a new mandate for flow meters to be installed at facilities with hydrogen clean service flares effectively replacing the previous methodology of calculated flows based on valve positions which was allowed for clean service flares, and continues to be allowed for non-hydrogen clean service flares. We note that the draft staff report does not include an economic analysis of this. The installation of a flowmeter is a non-trivial alteration to a critical safety system that requires extensive planning, design, and the purchase of custom equipment with long lead times. Installation has to be coordinated with the host facility and is expected to be done in conjunction with a curtailment or full shutdown of the host facility. Forcing a curtailment or shutdown of a refinery outside of the normal maintenance cycle can have significant local macroeconomic impacts. These impacts are also not mentioned in the staff report. 2-1

We suggest that instead of requiring a flowmeter to be installed within six months of rule adoption, that the District require one to be installed during the next maintenance turnaround, no later than five years from the date of rule adoption. This is consistent with language used by the Bay Area Air Quality Management District in their rule 13-5 regarding meters on process vents.

The term "flare tip velocity" is borrowed from 40 CFR Part 63 Subpart CC and is only defined in the context of a conventional elevated flare. The term is undefined and meaningless with respect to a multi-burner enclosed ground flare. We recommend that the district clarify the definition and state that it only applies to conventional flares. 2-2

Air Liquide

Paragraph (j)(5) implies that all facilities with flares are subject to 40 CFR Part 63 Subpart CC. However, our facility is not subject to this federal requirement on our flare due to the lack of organic hazardous air pollutants present in our process. Further, (j)(5)(B)(2) implies that all flare operators are refineries which is inconsistent with PAR 1118's purpose, applicability, and definitions. We suggest a clarification that this paragraph only applies to general service flares. Cont'd 2-2

Sincerely,

Eric KLEINSCHMIDT
Senior Environmental Specialist

**Staff Response to Comment Letter #2:**

## Response to Comment 2-1:

Staff acknowledges the technical complications and planning requirements associated with replacement of flow meters for hydrogen clean service flares and proposed to extend the due date for flow meter replacement project to up to 18 months after rule adoption to take into account the impact of turnaround schedule of hydrogen production plants with respect to implementation of such projects.

## Response to Comment 2-2:

Staff updated paragraph (j)(5) to address the ambiguity regarding the applicability of this provision to PAR 1118 hydrogen production plants, to be aligned with terms of applicability of U.S. EPA's Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

## *Comment Letter #3*

Feb. 22, 2024

COMMUNITIES FOR A BETTER ENVIRONMENT
established 1978

South Coast Air Quality Management District (AQMD)
Michael Krause, Heather Farr, Zoya Banan, Sarady Ka

Re: **Detailed CBE Comments on Rule 1118** - Earlier progress cutting oil refinery flaring has stagnated and even reversed; regulatory proposals to address this are still missing key tools

Dear AQMD Staff,

**CBE and other Environmental Justice organizations submitted a separate short letter Feb. 22, 2024, summarizing our concerns and recommendations on proposed flare Regulation 1118.** (Those recommendations are also repeated at the end of this letter.)

This letter provides technical support and additional information to support findings of that letter.

Refinery flaring and associated accidents have increased in recent years in total. In addition, frequent events emitted major levels of pollution in short periods ( >65,000 lbs of SOx, and over 40,000 lbs of VOCs concentrated over days, not years).

We must emphasize the reason the District commited to cutting flaring, and flare emissions in the first place – the pollutants directly harm people's health, and contribute to smog formation. It is not acceptable that this is considered by the Oil Industry as normal business practice. The Center for Disease Control found:

> ***Sulfur dioxide is severely irritating to the eyes, mucous membranes, skin, and respiratory tract.*** *Exposure to high levels can cause pulmonary edema, bronchial inflammation and laryngeal spasm and edema with possible airway obstruction.* ***Chronic exposure*** *can result in . . .* ***increased susceptibility to respiratory infections, symptoms of chronic bronchitis, and accelerated decline in pulmonary function. Chronic exposure may be more serious for children*** . .

Furthermore the Air District's AB617 Community Emission Reduction Plan for Wilmington, Carson, West Long Beach found that the presence of several petroleum refineries caused the largest contribution of VOCs in this area.[1]

Flaring also causes major smoking events, like that pictured at right from last year (described later). Such events happen regularly. These emit toxics and particulate matter, adding to the burden of invisible SOx and VOC pollution.

Thank you for your consideration of the following details, urging adoption of all reasonably available control measures at this late juncture (after decades of flare regulation when such events should have been a thing of the past).

---

[1] SCAQMD, Wilmington, Carson, West Long Beach Community Emission Reduction Plan, Sept. 2019, Final, p. 3b-6, *["The largest contribution to VOC emissions are from petroleum production and marketing, due to presence of several petroleum refineries in this community."]*, available at https://www.aqmd.gov/docs/default-source/ab-617-ab-134/steering-committees/wilmington/cerp/final-cerp-wcwlb.pdf?sfvrsn=8

## I. Details of rule-strengthening needed in proposed updated Rule 1118

### *A. The proposed **Annual SOx Target** is too lax—**refineries already achieved far lower levels*** 3-1

The proposed rule sets an Annual Performance Target at 0.25 tons SOx per million barrels of crude oil processed by 2028. Although this is tighter than past targets in the rule, most facilities *already* have done far better in practice to reduce this harmful pollutant.

**In fact, the District's table below shows many refineries previously met 0.10 tons SOx per million barrels crude oil (and far lower).** We propose no higher than this level should be considered. We also propose accelerating the deadline to *2026*.

This annual target provides a limit on the lump sum of all types of SOx flaring in one year. It is a major strategy AQMD used to make progress reducing overall SOx. Now the District is hampering its own efforts, by chosing a target too lax to move us forward in long-delayed regulatory updates. It would be much better to wait a month than to hurry at the end, leaving us without bringing SOx flaring levels at least down to those achieved in the past.

**While refineries have already shown they can meet 0.10 tons (below), if they did *not*, they can still operate** – they would only have to pay fees to AQMD until the next year. The staff report found such disincentives effective in reducing emissions in the past.

AQMD's own Table 3-3[2] shows a target of <0.10 was already achieved at multiple refineries:

- **Since 2012 Marathon Carson achieved 0.10 tons/million barrels crude every year** (and its average since 2012 was less than 0.03, and never higher than 0.08).
- **Since 2017 Chevron achieved it 3 out of 5 years** (and was close in 2012 and 2016).
- From **2013-2016 Marathon Wilmington achieved it every year** (as well as 2018 and 2020).
- **TORC achieved it in 2021 and was close to achieving it in 2020.**
- Only Phillips 66 failed to achieve 0.10 since 2012.
- **Half the refineries got worse in later years, indicating a need for tighter standards, higher fines, and stronger enforcement, to prevent backsliding and make forward progress.**

**Table 3-3. $SO_2$ Emissions per Processing Capacity by Refinery**

| Year | Chevron | Marathon Wilmington & SRP | Marathon Carson | AltAir Paramount | Valero | TORC | Phillips 66 |
|---|---|---|---|---|---|---|---|
| 2012 | 0.11 | 0.59 | 0.02 | 0.001 | 0.48 | 0.80 | 0.61 |
| 2013 | 0.29 | 0.07 | 0.06 | 0.000 | 0.21 | 0.40 | 0.31 |
| 2014 | 0.29 | 0.04 | 0.00 | 0.000 | 0.54 | 0.50 | 0.57 |
| 2015 | 0.23 | 0.01 | 0.03 | 0.003 | 0.13 | 1.90 | 0.91 |
| 2016 | 0.13 | 0.08 | 0.01 | 0.001 | 0.63 | 0.30 | 0.30 |
| 2017 | 0.00 | 0.17 | 0.02 | 0.001 | 0.15 | 0.70 | 0.30 |
| 2018 | 0.11 | 0.01 | 0.03 | 0.001 | 0.01 | 0.20 | 0.74 |
| 2019 | 0.07 | 0.43 | 0.02 | 0.000 | 0.01 | 0.20 | 0.47 |
| 2020 | 0.03 | 0.06 | 0.08 | 0.001 | 1.10 | 0.11 | 0.20 |
| 2021 | 0.16 | 0.64 | 0.06 | 0.001 | 0.51 | 0.10 | 1.02 |

[2] SCAQMD Reg. 1118 staff report, p. 3.3

2

Setting an achievable but strong standard, based on the tightest achieved in practice is a reasonably available control and a time-honored, successful strategy to reduce health-harming emissions. If the 2020 and 2021 years higher emissions were anomalies due to the pandemic, that is all the more reason to set a standard based on the many years of tighter SOx levels met before. Cont'd 3-1

**Contrary to arguments of the Oil Industry, questioning why the District would want to substantially reduce refinery SOx emissions, it should be no surprise to most that Sulfur Oxides are very harmful to health.** The Center for Disease Control's Agency for Toxic Substances and Disease Registry (ATSDR) found:[3]

> ***Sulfur dioxide is severely irritating to the eyes, mucous membranes, skin, and respiratory tract.*** *Exposure to high levels can cause pulmonary edema, bronchial inflammation and laryngeal spasm and edema with possible airway obstruction.*
>
> ***Chronic exposure*** *can result in an altered sense of smell (including increased tolerance to low levels of sulfur dioxide),* ***increased susceptibility to respiratory infections, symptoms of chronic bronchitis, and accelerated decline in pulmonary function. Chronic exposure may be more serious for children*** *because of their potential longer life span.*

**Oil Refineries are major sources of SOx in the South Coast.** While refineries emit SOx from many *continuous* sources of pollution, episodic emissions from oil refinery flares can dump large volumes of SOx to the air in a short time, suddenly adding many tons in one day or a even a few hours.

Furthermore, SOx emissions are precursors to deadly particulate matter formation. The American Lung Association found: *"There is no safe threshold to breathe in fine particles. A recent review of all available scientific evidence to date clearly shows that particle pollution is associated with increased mortality from all causes, cardiovascular disease, respiratory disease and lung cancer."*[4]

The charts below show the largest of both SOx and VOC flaring in 2020-2022. (These do not show many other smaller flaring events that also dump cumulatively large volumes of SOx and VOCs to the air each year). SOx reductions from refineries was a major goal set by the Wilmington, Carson, Long Beach Community Emission Reduction Plan (CERP), although SOx reductions have also been an important goal of the District since its inception, due to the harmful impacts on health.

### *B. An Annual VOC target is completely missing* 3-2

An Annual VOC target is necessary because the SOx target cannot by itself disincentivize high-VOC flaring with *lower* SOx emissions). Two different targets are needed for SOx and VOCs. **Of course, VOCs are well-established as very harmful to air quality.** They are smog precursors, in the region with the worst smog in the nation, and are directly toxic as they include chemicals like carcinogenic

[3] Medical Management Guidelines for Sulfur Dioxide, available at: https://wwwn.cdc.gov/TSP/MMG/MMGDetails.aspx?mmgid=249&toxid=46#:~:text=Sulfur%20dioxide%20is%20a%20severe%20irritant%20to%20the%20respiratory%20tract,edema%20with%20possible%20airway%20obstruction.

[4] American Lung Association, Particle Pollution, What Are the Health Effects of Particle Pollution?, available at: https://www.lung.org/clean-air/outdoors/what-makes-air-unhealthy/particle-pollution

3

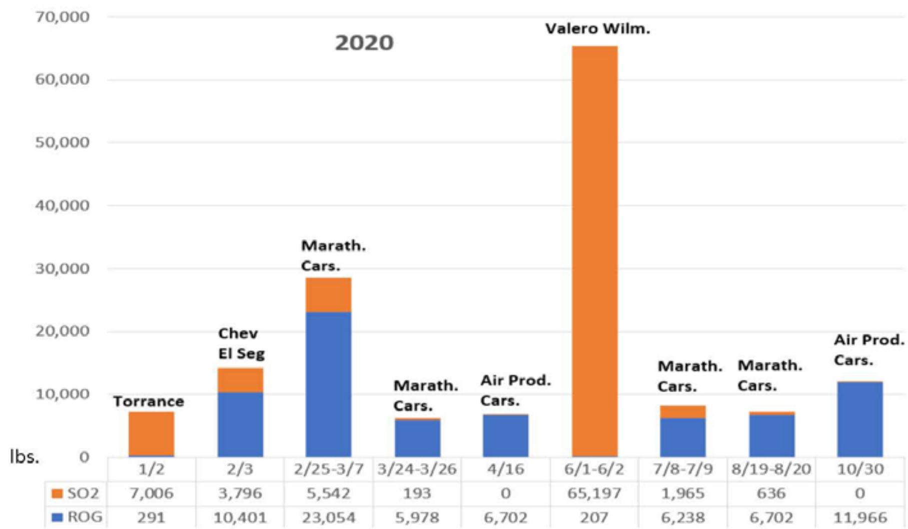
benzene. These emissions are not equally distributed across the region – they are concentrated in refinery towns - low income and communities of color. Cont'd 3-2

**In fact, AQMD's AB617 CERP for Wilmington, Carson, West Long Beach found that the presence of several petroleum refineries caused the largest contribution of VOCs in this area.**[5]

CBE charted large emission events of 2020, 2021, and 2022, from AQMD public records received pursuant to Regulation 1118. Some of these occurred over multiple days. This showed:

- 2020: **7 of 9 largest flaring events were high-VOC, lower SOx.**
- 2021: High SOx events dominated, but this year still had **six large VOC emitting events**, each with thousands of lbs. of VOC emissions.
- 2022: **VOCs again dominated the largest flaring events.**

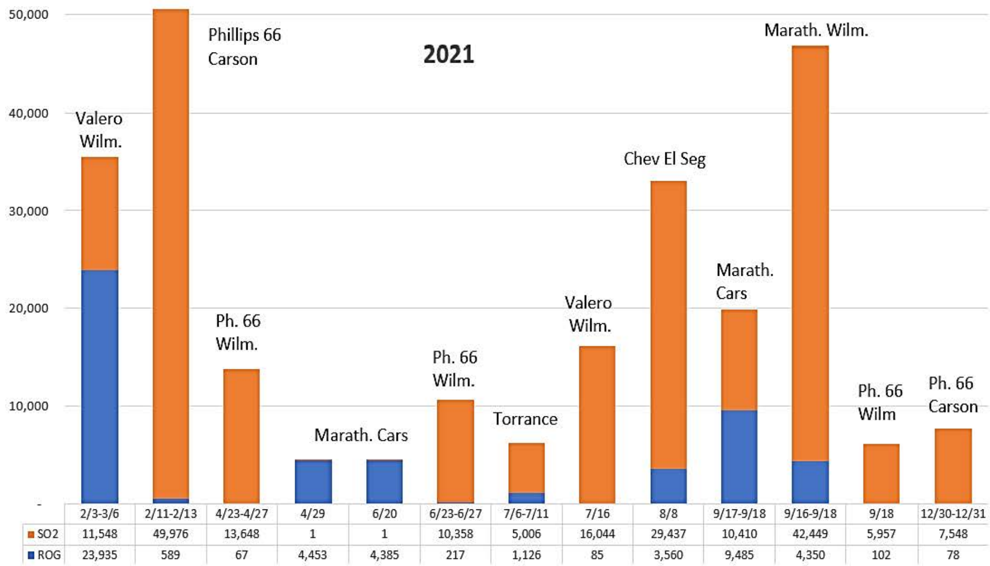
*(Note that flare combustion efficiency (of VOC destruction efficiency) can go far lower, so that VOCs emissions would be even higher, including those large events below.)*

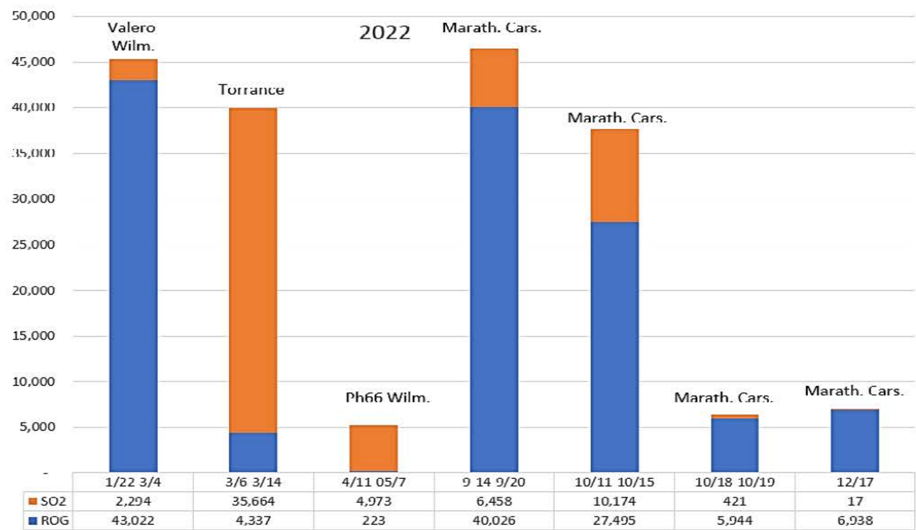



[5] SCAQMD, Wilmington, Carson, West Long Beach Community Emission Reduction Plan, Sept. 2019, Final, p. 3b-6, *["The largest contribution to VOC emissions are from petroleum production and marketing, due to presence of several petroleum refineries in this community."]*, available at https://www.aqmd.gov/docs/default-source/ab-617-ab-134/steering-committees/wilmington/cerp/final-cerp-wcwlb.pdf?sfvrsn=8

4

Cont'd
3-2



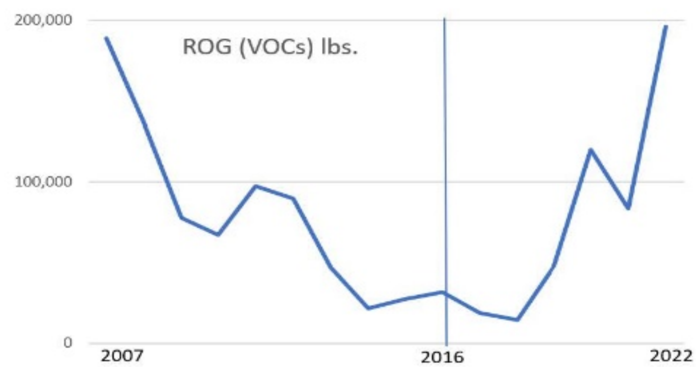




The charts above don't even show the full extent of the VOC flaring problem – only the largest events.
**Frequent smaller events occur every year, adding up to hundreds of thousands of pounds.**

5

In addition to individual events, total annual emissions can be graphed. Based on aggregated quarterly data reports AQMD provides online, we charted the trend in total VOCs from flares over the years. *(2016 is delineated because Torrance had particularly high flaring that year, with major Notices of Violation.)* Note that after the 2017 flare rule update, some VOCs changed to higher emission factors. (EPA found flare destruction efficient not as high as assumed, resulting in higher emissions). Thus VOCs post-2017 are not directly comparable to previous years (which would have been shown even higher emissions.) Cont'd 3-2

Regardless of changes in emission factors post 2017, the chart clearly shows that **past VOC flaring emissions were headed down, but in recent years VOC flaring emissions are headed up.** Total emissions are in the hundreds of thousands of pounds, concentrated in refinery communities.




**We urge AQMD to apply to VOCs the same method used to chart tons of SOx per million barrels of crude oil at each refinery, each year** (as in Table 3.3 shown earlier).[6] This would identify the best annual VOC levels of the past, to help identify best practices toward lowering VOC emissions. (We could do the analysis ourselves with available data, but it would be helpful to have such a chart in AQMD's staff report, which includes many other valuable charts).

*(In addition to the need for this target for refineries, it is unclear whether proposed standards for "Clean Service" flares outside of refineries will sufficiently limit VOCs. See below.)*

***C. Each facility should do Flare Minimization Plans (FMPs) yearly to prevent repetition of the previous years' flaring causes*** 3-3

It is crucial that refineries rigorously review the unplanned causes of flaring that have occurred in the past, and ensure these are not repeated. Each refinery is customized, and unplanned flaring is caused by a wide variety of accidents, but breakdowns are common. These can include breakdown of varied process control equipment in different refinery units, temperatures too high, other necessary process parameters out of specification in various process units, loss of steam, compressor breakdown, power outages,and any malfunctions that causes shutdown and subsequent flaring.

[6] As in the Annual SOx target in Table 3.3 shown in the previous section.

6

**Failure to prevent predictable repeated breakdowns can be illegal, according to U.S. EPA:**

> *EPA, believes that repeated malfunctions for the same cause, generally, could be predicted and prevented. If flaring results from a preventable upset, EPA believes that it does not represent good air pollution control practices and that it may violate the CAA [Clean Air Act].*[7]

Cont'd 3-3

Therefore maintaining and updating Flare Minimzation Plans (FMPs) each year in order to prevent repeat malfunctions needs to be required at each refinery. FMPs should also address minimization of Planned Flaring, and ensure routine flaring does not occur.

**It is unclear whether the Air District rigorously reviews and enforces actual flare minimization in FMPs, or just accepts FMPs as a rote exercise.** Given flaring increases in recent years and unplanned flaring event numbers almost doubling,[8] it appears that enforcement of flare minimization is not happening. It would be helpful to know whether refineries received violation notices for the increased number of unplanned flaring events due to failure to meet general flare minimization requirements, or whether such increases were considered acceptable by the District under the current rules.

The Air District should ensure sufficient fees are charged to refineries and other facilities subject to the rule, so that AQMD is sufficiently staffed to evaluate FMP effectiveness. Fees and fines should later be further increased, if FMPs are found ineffective in minimizing flaring.

### D. *Flare video monitoring with online realtime access is needed to enforce against flare smoking and other violations*

3-4

Staff proposed last year to add realtime online video-access requirements to Rule 1118, but only late in the process have oil companies opposed, and succeeded in strickening this highly practical and innovative proposal.

*July 11, 2023 - Phillips 66, photo provided to Alicia Rivera, CBE, by CBE member*

At right is a photo of a Phillips 66 smoking flare event, 7/11/2023, showing the dramatic black smoke that can come from flares. Many other smoking flaring events occur, including the event 2/9/2024 nighttime event, shown on the next page.

**Flare regulations limit smoke to 5 minutes,**[9] because smoking is a source of additional pollution (beyond the invisible SOx and VOCs), including particulate matter emissions that further harm air quality.

**It is impossible for inspectors to be on the spot in less than 5 minutes to see smoking.** In fact, AQMD staff recently said during a hearing that having an inspector make it out in two hours is expeditious. These are the realities of logistics, but realtime video can entirely solve the problem. Video technologies are well-developed and readily available.

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[7] This has long been the case, as described in U.S. EPA's Enforcement Alert*: Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases Practice Not Considered 'Good Pollution Control Practice'; May Violate Clean Air Act*, 2000, https://www.epa.gov/sites/default/files/documents/flaring.pdf

[8] SCAQMD draft staff report, Jan. 2024, p. 2-12, **unplanned flaring events increased steadily from 129 in 2020 to 232 in 2023**

[9] Rule 1118 - (d)(1)(B) Operate all Flares in a smokeless manner with no visible emissions except for periods not to exceed a total of five minutes during two consecutive hours, as determined by the test method in paragraph (k)(2).

7

**We have been told many times by regulators that a particular flaring event or accident reported by community members had not yet been reported by the refinery or other facility.** In one example of another flaring event (not to be confused with the Phillips event above), Alicia Rivera, CBE Wilmington Community Organizer reported to CBE's Wilmington team via email that on 7/21/22 a Valero flaring event occurred: Cont'd 3-4

> *Interesting facts about the latest Valero flaring of last night, and how important it is for us/members to see and report flaring. Talking to the inspector I found out that:*
>
> ***1) Valero did not report the incident to AQMD***
>
> ***2) FENS (flare notification sys.) did not go on***

Giving AQMD staff realtime access to online flare video monitoring will help inspectors to: 1) check immediately if a flare is smoking, 2) take follow-up action to determine if there is an emergency happening at the refinery, especially if community response is needed, and 3) determine if rule violations occurred.

*Another flare smoking event, with smells, this month - 2/9/2024, Phillips 66, Wilm. CA, Ashley Hernandez, CBE*

We can't tell whether flaring receives Notices of Violation or not. **We do not think that the Air District currently comprehensively tracks such harmful flare smoking** (it appears hit or miss), and we don't think the associated emissions and health impacts are assessed.

But video monitoring provisions proposed by staff many months ago have fallen prey to oil industry arguments that video monitoring of flaring represents a security threat. Does that mean that neighbors looking at flaring from their homes, and recording it, represent a security threat? This is nonsensical. It is not necessary for online video monitoring to be connected into oil refinery control systems, they can be separated, and handled securely.

**Please note that during Aparatheid in South Africa, oil refinery emissions in black communities were official state secrets.[10]** This was absurd, immoral, and racist. Yet today in the South Coast, the Oil Industry has killed the staff proposal for simple provisions for online realtime video monitoring, using tactics reminiscent of this, based on Homeland Security.

**Realtime online visual data of smoking flares is a bona-fide air quality monitoring tool to detect visible smoke, just as *infrared* cameras monitor a different part of the spectrum** to detect invisible VOCs (eg for storage tanks). Outside the refinery, people can and sometimes do film and record visible

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[10] **Brian Maguranyanga, Engen Refinery in South Durban, South Africa International Case Studies, University of Michigan, available at https://websites.umich.edu/~snre492/cases.html , (page last updated 2004),** *[". . . Apart from being the largest oil refinery in Durban as well as one of the two largest source of sulphur dioxide pollution in South Durban, Engen Refinery is closely located to two residential low-income black communities, Merebank and Wentworth. . . .* ***During the apartheid era, the refinery was considered a strategic infrastructure or National Key Point, and thus was able to avoid close scrutiny from the public regarding its environmental impact and public health costs. The refinery operated under the Official Secrets Act, which prevented us from dealing at any level with the public about the business*** *[a refinery manager's view as quoted by Sven Peek]. . . .* ***The community identified the problem areas to include regular flaring, sulphur dioxide emissions,*** *and oil spills, etc. However, the management responded by arguing that the pollution was wind-blown from other factories, flaring occurred for safety reasons, and that some oil spillage was beyond their control." . . .]* **[emphasis added]**

8

black clouds and large flames at refinery flares for themselves, but this unnecessarily burdens the public with the job of documenting air quality harms. Cont'd 3-4

Continuous video monitoring with online access is a key tool for improving refinery emissions performance and reducing harmful emissions, and must be reinstated.

***CBE Youth Member regarding Refinery Flaring experience*** *(excerpt below, full statement attached)*

. . . I'm a junior who just turned 17. I'm writing to you as a frontline resident living and attending school in Wilmington, CA that has high emissions due to refineries, oil extraction, and high diesel traffic in my community. . . . A home is where you are supposed to feel secure, but when these flares happen I get scared and confused, not knowing what's going on now.

**. . . I've witnessed black smoke and strong smells in my home . . .** It smelled that bad. **My brother and sister both have asthma and are really affected by these flares. They often start wheezing or need to use their inhalers because they can't handle the fumes anymore.** These flares put the people in my life in actual danger. Not to mention how the color the whole turns orange at night when these flares happen. I often will see just flashes of orange light coming outside my window, and at times I'd even witness smoke. When there's smoke that's when I'm most concerned.

. . . We need a stronger regulation. Please do not proceed to adoption until you add a standard for VOCs, a stronger standard for Sulfur Oxides, and **realtime video camera monitoring to record black smoke.**

*E. Long-neglected "Clean Service" and Hydrogen Flares have new requirements* 3-5

We are grateful for the staff's detailed work beginning the scrutiny of so-called "Clean Service" flaring (of VOCs and hydrogen), which staff found to be extensive in the District.

This category was defined as burning natural gas, Liquified Petroleum Gas (LPG), other low-sulfur streams, and hydrogen. (Now hydrogen flaring is being separated into its own new category.) *These flares contrast with general service flares, which burn gases from many parts of the refinery, including high-sulfur streams.*

**"Clean Service" is a misnomer.** Past District flare rules focused mainly on reducing SOx, so that low-sulfur flare streams were called "clean". But this failed to recognize the importance of VOC and NOx emissions (and the understimation of VOCs) at clean service, and all flares.[11] Misnaming is not without consequence – such flares were underregulated and have even been misrepresented as non-polluting by AQMD inspectors when responding to flare reports by neighbors. We accept that inspectors believed these flares were clean – after all, District regulations specifically label them as clean. **It is time to correct such misleading regulatory definitions, striking "Clean" Service, and renaming as "VOC" or "Hydrogen" Service flares.**

[11] While general service flares have higher total emissions and emit additional pollutants (like SOx), Clean Service flares have significant emissions without much regulation. Also, clean service flares *do* contain some sulfur, particularly at Phillips 66 Wilmington, which included thousands of pounds per year of SOx emissions from "clean service" flares.[11] Working Group Staff Report, Figure 2-7. Sulfur Dioxides Content from Clean Service Flares by Facility, p. 2-7

9

Cont'd 3-5

**Two refineries were identified by the staff as <u>continuously</u> flaring at so-called "Clean Service" flares.**[12] Staff found: *"Significant flaring occurs at 2 out of 3 clean service flares"; "Gas flow from clean service flares represents high share out of the total flared gas at these refineries"; and "Staff is considering limiting the frequency of clean service flaring".* [13]

The non-hydrogen "clean service" LPG flares *"are dedicated to the LPG storage or loading areas of refinery. . . . **the majority of them are not integrated with refinery vapor recovery system**. Flaring at LPG flares occurs when LPG vapor is relieved from pressure control valves or pressure safety valves (PSV) of storage tanks/vessels, when the LPG tanks/vessels are being de-inventoried for cleaning or inspection, and during turnaround maintenance."*[14] [emphasis added]

**Consequently, staff proposed a new throughput limit of 15,000 million BTUs per year before adding refrigeration to tanks, to limit flaring at LPG storage, an important step forward.** However, it is unfortunate that unlike other refinery systems where routine flaring is not allowed, LPG flares aren't required to recover and recycle propane and butane inside the refinery (connecting with vapor recovery). This routine flaring likely is not in accordance with the EPA Enforcement alert (cited earlier) regarding good pollution control practices, since refineries do have places they could use these gases, rather than burning them.

**AQMD staff have also added an important new NOx standard for Clean Service flaring, recognizing that: *"All flares, including clean service flares, are a significant source of NOx emissions.*** *NOx emissions are the most significant precursor of ground level ozone formation and the South Coast AQMD must reduce these emissions wherever feasible."*

As in the choice of the annual SOx standard, the proposed NOx standard is not based on the *lowest* levels already achieved. The staff report found for hydrogen flares:

> *"NOx emissions have <u>ranged from zero to 0.37 pounds</u> per hydrogen production capacity (lbs/MMscf) over the last ten years and the emission vary based on operational needs and unit maintenance. . . The proposed NOx performance target is <u>0.3 pound[s]</u> per million standard cubic feet (MMscf) . . ."*

**It may be *temporarily* sufficient to start with a NOx limit near the *top* of the range achieved since the standard is new.** But the District should commit to review and consider tightening the NOx standard in a few years, evaluating the *lowest achievable NOx level*. The District needs all possible NOx reductions for all sources, beyond existing regulations. Since Hydrogen Plants are seeking to expand, the new NOx standard reductions will be in danger of being offset by increased production.

VOC emissions from "Clean Service" (non-hydrogen) flares are also underestimated (below).

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Meeting #3, April 26, 2023, AQMD Presentation, Slide 14, available at https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1118

[13] Working Group Meeting #3 Presentation, April 26, 2023, available at https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1118

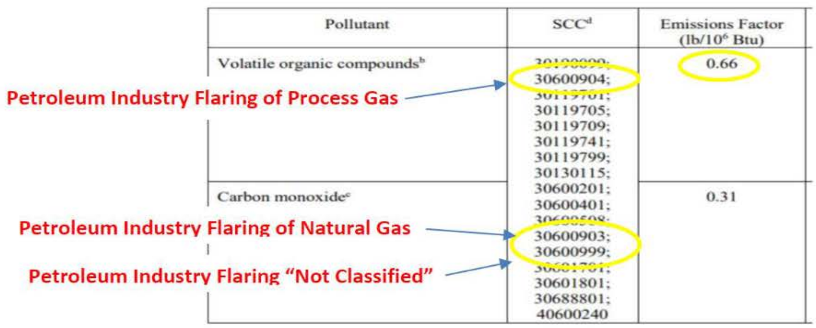
[14] Staff report, p. 3-5

10

*F. EPA found much higher Emission Factors for flaring Methane, Propane, and Butane* 3-6

Note that in 2017, CBE submitted the following comments on Rule 1118 updates at that time, regarding the great understimation of emissions factors for certain hydrocarbons –methane, propane and butane. EPA had already found emission factors for all process gas, and including flaring Natural Gas, and gases "Not Classified" -- at 0.66 lbs/MMBTU (in table below).

**EPA Table 13.5-2 VOC & CO Emissions Factors for Flare Operations**



| Pollutant | SCC[d] | Emissions Factor (lb/10[6] Btu) |
|---|---|---|
| Volatile organic compounds[b] | 30190099; 30600904; 30119701; 30119705; 30119709; 30119741; 30119799; 30130115; 30600201; 30600401; 30600508; 30600903; 30600999; 30601701; 30601801; 30688801; 40600240 | 0.66 |
| Carbon monoxide[e] | | 0.31 |



By contrast, the District regulation:

- Defines emission factors for <u>propane and butane</u> flaring at <u>0.009</u> lbs/MMBTU VOCs to atmosphere (**73 times lower than EPA**) and <u>Methane</u> flaring at 7 lbs/MMSCF (equivalent to ~<u>.007 lbs/MMBtu</u>[15]) or **94 times lower** than EPA's 0.66.
- EPA's much higher VOC factor of <u>0.66</u> lbs/MMBTU is <u>only used by the District for "vent gas"</u> flaring.
- Further, EPA's emission factor is based on achieving very high combustion efficiency and on sufficient heat content and flare tip velocity to maximize VOC destruction. If these conditions are *not* met, emissions can be even worse.

**We urge the District to update the emissions factors for flaring of natural gas, propane, and butane, to at least as high as EPA's VOC factor of 0.66 lbs/MMBtu for all flaring of hydrocarbons.** The current underestimation of emissions also underestimates the value of preventing flaring emissions, and of adopting all reasonably available control measures. It emphasizes the flaw in assuming VOC impacts are low compared to SOx impacts.

This underestimation also undermines the District's cost-effectiveness calculations for controlling routine flaring from LPG tanks (discussed above). With propane and butane emissions upward of 73 times higher, cost per ton of reduction is also 73 times less. **The District, after correcting the emissions factors to these much higher levels should re-calculate the cost-effectiveness of controls for non-hydrogen clean service flares.**

[15] Methane has about 1020 BTU/scf, so 7 lbs/1,000,000 SCF / (1020 BTU/SCF) ≈0.007 lbs/MMBTU, and EPA's factor for flaring methane is 0.66 lbs/MMBTU / 0.007 lbs/MMBTU = 94 times higher than the District factor.

11

Cont'd 3-6

**This is another reason why specialized Remote Sensing of flares (discussed below) is needed.** Especially for flares that operate almost continuously, the District would not have to wait for a flaring event to carry out the monitoring. The District should identify contractors who can perform this monitoring and at least begin pilot testing of flare destruction efficiency and actual VOC emissions.

3-7

***G. In 2017 Flare Rulemaking, future Remote Sensing of flares was promised by AQMD, after EPA's remote sensing found much higher flare emissions***

During the 2017 Rule 1118 update 2nd workshop, *March 22, 2017*, District staff presented the following slides 21, 22, and 23, which summarize Flare Remote Sensing well (highlights added) stating the *"Purpose of Remote Sensing is to more accurately determine emissions and to provide feedback on flare destruction efficiency"*

## Flare Remote Sensing Pilot Program

- Purpose of Remote Sensing is to more accurately determine emissions and to provide feedback on flare destruction efficiency
  - Primary focus will be on Volatile Organic Compounds
- Evaluate multiple remote sensing technologies at multiple refineries
  - Logistics, cost, quality of data
- Data collected during Pilot Program compiled in a final report and made publicly available
  - Emissions data collected during Pilot Program not intended for compliance or fee purposes
- Incorporation of remote sensing requirements into rule pending assessment of Pilot Program

## Monitoring of Flare Destruction Efficiency

- Flare destruction efficiency a significant factor for determining Volatile Organic Compounds (VOCs) emitted during flaring
- New monitoring technologies becoming available to directly measure flaring emissions
  - EPA used some of these new technologies to determine a new VOC emission factor that is ~10X higher than current Rule 1118 emission factor
- Recent SCAQMD-funded study that investigated total refinery VOC emissions using optical remote sensing technologies observed one flaring event in 2015

| Estimation Method | Pollutants Measured | Emissions (pounds) |
|---|---|---|
| Rule 1118 VOC Emission Factor (Reported for 24-hour period) | Total VOC | 244 |
| EPA AP-42 Emission Factor (Using same 24-hour period) | Total VOC | 2,556 |
| SCAQMD-funded study (Observed over 4 hour period) | Fraction of VOC (non-methane alkanes only) | 6,355 ± 4,103 |

12

Cont'd 3-7


US EPA found 10 times higher flare emissions for one event (over 24 hours) compared to when using the District's assumed high VOC flare destruction efficiency. AQMD measurements above found an even higher difference, (43 times higher emissions) for a four-hour period. This is consistent with evidence that we have submitted over the decades, since many studies show flare efficiency can vary widely.

We noted that at the October 25, 2023 workshop, Providence Photonics presented their remote sensing method, with added control to optimize steam (to both measure and reduce flare emissions).[16] But at the Feb. 8th workshop, AQMD found flare remote sensing infeasible, because the method did not yet have EPA approval.[17] However, AQMD has regularly authorized use of its own test methods or alternate methods, (not relying on EPA).

**We propose the District re-commit to Remote Sensing emission characterization by a date certain (within 3 years)**. If it finds lower destruction efficiency and resultant higher VOC emissions, the District should correct its rules and emissions inventory. It is important to refine the emissions inventory to reflect true impacts of sources (whether from flares, storage tanks, or other emission underestimations).

***H. Definition loopholes*** 3-8

**"Essential Operational Needs"** include a long list of activities, excusing refiners from flare minimization *by definition*.[18] This category is not present in Bay Area regulation[19] and should be eliminated as unecessary and counterproductive. (This was introduced in early regulation, when AQMD had little experience regulating flaring, but the Bay Area never included this category.)

[16] Providence Photonics, The VISR Method for Flare Monitoring, Oct. 25, 2023 during Rule 1118 Meeting #4, available at: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118/providence-photonics-presentation-on-remote-sensing-of-flare-efficiency.pdf?sfvrsn=8

[17] Proposed Amended Rule 1118: Control of Emissions from Refinery Flares Public Workshop February 8, 2024, Slide # 9, [*"Remote optical sensing for flare emission characterization – ● Deemed infeasible at this time: ●Technology under review by U.S. EPA, but not approved".],* https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118/par-1118-pw-presentation-20240208.pdf?sfvrsn=15

[18] SCAQMD Rule 1118: "(c)(14) **Operate all flares in such a manner that minimizes all flaring** and that no vent gas is combusted **except during emergencies, shutdowns, startups, turnarounds or *essential operational needs*."** [emphasis added]

[19] BAAQMD, Regulation 12-12:Flare Minimization Plan requirement (12-12-301): *"This standard shall not apply if the APCO determines, based on an analysis conducted in accordance with Section 12-12-406, that the flaring is caused by an emergency and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere."*

13

*I. Public access to SCAQMD flare data has been unecessarily difficult, contrasting with BAAQMD provisions for daily flare data, online since regulation adoption.* 3-9

**We appreciate the extensive work of the Public Records staff who provided us with flare data and root cause analysis in hundreds of spreadsheets and reports, pursuant to Rule 1118.** We have made such Public Records Act (PRA) requests every few years to review updated data, because the South Coast website only provides quarterly aggregates, not measured daily emissions. It takes months to receive data.

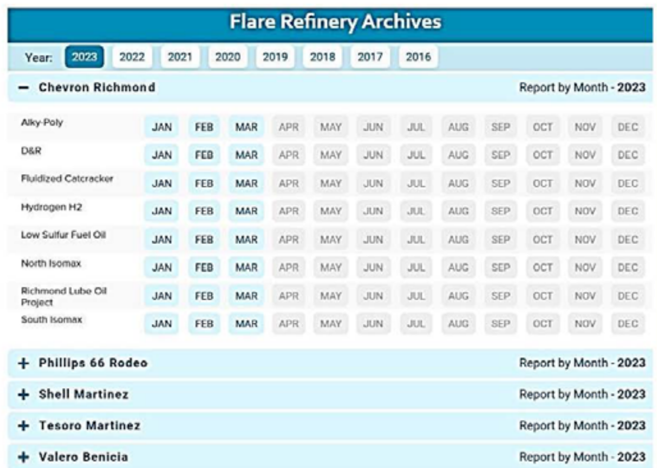
**We also appreciate the engineering / regulatory staff addressing our concerns through a proposal to add flare emissions online to the FENS website.** This will help the public, regulators, and refiners. Community members experience flaring smoke, odors, and bright lights at night, and deserve data quantifying event emissions. Good data access is also essential in leading to solutions. The Bay Area has provided such daily data online since its flare regulation was adopted (published online about a month later). The South Coast can use and improve on this example, with a few additions for accessibility.

In addition to the daily emissions and flow for each event at each separate flare, adding a running daily total by SCAQMD for each refinery on SOx, VOCs, and total flow would greatly increase accessibility beyond what the BAAQMD provides.

**Right now, in the Bay Area data, the public has to look in each separate flare file, each month, at each refinery, each day, to determine if there were flare emissions that day.**

Each refinery has many different flares (Chevron Richmond at right has eight), so it is still hard to find which days have flaring without opening many folders.

***Bay Area online data provides daily flaring data for each month, flare, and refinery.***




**SCAQMD should require an additional chart, totalling emissions at each separate day as the years progress, at each refinery, to make it easier to see when events occurred.** This would immediately show big events, rather than requiring looking through 84 separate files, in the Chevron Richmond example above. Annual totals, and measures of annual targets for SOx, VOCs (and NOx, discussed below), should also be provided, in tons per million barrels of crude oil processed. In the case of non-refiners (which do not process crude oil but are subject to the rule), totals should also be provided.**In addition, any preliminary information about cause of flaring would be very helpful.**

We understand that staff is planning to provide additional public process after adoption of Rule 1118 regarding FENS website format. However, there may be additional provisions needed in Rule 1118 itself needed now to ensure refinery data will be submitted in a form that will facilitate public access to flare data (already submitted to AQMD pursuant to existing Rule 1118 requirements)..

14

## II. Summary of Recommendations

3-10

We urge the following improvements to the draft regulation (and moving adoption to May):

1) **The proposed 2028 Annual SOx emission target is so loose, most refineries already met far tighter standards years ago.** It acts like a backstop, not an achievable improvement.

   - *Tighten to <0.10 tons SOx per million barrels crude oil processed, which has already been met by multiple refineries (instead of 0.25, a step backward).*

2) **An Annual VOC target is entirely missing** – there is *no* such standard to address high-VOC, low-SOx events missed by the annual SOx target.

   - *Set a similar achievably low VOC target, based on long-term flare data, since such targets for SOX were found effective by the staff.*

3) **Flare Minimization Plans are not required every year**

   - *Require annually, ensure they plan to prevent causes of large flaring of previous years.*

4) **The oil industry killed staff-proposed Online Video Monitoring which could document harmful *smoking* flare violations** that would otherwise be missed by AQMD enforcement. Vague Homeland Security arguments were used by the industry, reminiscent of South African censorship during Apartheid (when refinery emissions were defined as official state secrets). This is absurd—neighbors can see and film flaring, but District staff must travel long distances, frequently arriving too late to see and enforce against smoking flare violations, unless staff has access to realtime flare video.

   - *Reinstate staff-proposed realtime online flare video monitoring.*

5) **The District promised in 2017 to carry out specialized Remote Optical Sensing of flares** to improve emissions understimations, but now says communities must wait until EPA develops its test protocol (though the District has many of its own protocols).

   - *Commit to Remote Sensing by a date certain (within 3 years).*

6) **Other key amendments are needed** including correcting low-ball VOC calculations (inconsistent with EPA), more comprehensive prevention of constant flaring at hydrogen and so-called "Clean Service" flares, definition loopholes, improvements in public access to online data.

15

We acknowledge steps forward made by the District toward reducing emissions from refineries, and highly appreciate the staff's attention to these issues.

At the same time, the District as a whole does not always seem to recognize the severity and level of pollution, accidents, smoke, flaring, and cumulative impacts from a variety of Oil Refinery emissions, added to the variety of other pollution sources endured by people in Wilmington, Carson, West Long Beach, (as well as by the other refinery communities in El Segundo and Torrance).

It is surprising to us that we have to work very hard to justify the need for pollution reductions in these communities.

The onslaught of refinery accidents (which frequently cause flaring) is unrelenting and traumatizing, and the onslaught of pollution from all the different fossil fuel sources in these communities is devastating to health, and to climate safety.

We urge the District to adopt all Reasonably Available Controls for Refinery Flares.

*Another bright, disruptive, flaring event with strong, irritating smells - Valero Wilmington Refinery Flaring 7/20/22, Photo by Maria Gonzalez, CBE member. Flaring was so bright, she was awakened at night, and thought the house was on fire. Smells were bad, requiring shutting up windows. This was unreported to Air District by the refinery until she called.*

Sincerely,

Julia May, Senior Scientist
Communities for a Better Environment (CBE)

16

ATTACHMENT - CBE Youth Member has submitted this statement to us for AQMD:

**(Other such statements will be submitted later – some members were not able to speak at the public workshop, due to technical difficulties)**

3-11

My name is Sheelsie and I'm a junior who just turned 17. I'm writing to you as a frontline resident living and attending school in Wilmington, CA that has high emissions due to refineries, oil extraction, and high diesel traffic in my community. Today I'm concerned about flaring in my community and the updates to the refinery rule because flaring happens when I'm idly minding my business in my own home. A home is where you are supposed to feel secure, but when these flares happen I get scared and confused, not knowing what's going on know We need strong regulations to understand and capture the real impacts that are being emitted in my community. Don't allow for delays and implement stronger regulations! I've witness black smoke and strong smells in my home almost as if someone set a fart bomb in my house. It smelled that bad. My brother and sister both have asthma and are really affected by these flares. They often start wheezing or need to use their inhalers because they can't handle the fumes anymore. These flares put the people in my life in actual danger. Not to mention how the color the whole turns orange at night when these flares happen. I often will see just flashes of orange light coming outside my window, and at times I'd even witness smoke. When there's smoke that's when I'm most concerned We know the District has been working for many decades to regulate Oil Refinery flaring, so we don't want to wait longer for adoption of ALL REASONABLY AVAILABLE CONTROL MEASURES. We need a stronger regulation. Please do not proceed to adoption until you add a standard for VOCs, a stronger standard for Sulfur Oxides, and realtime video camera monitoring to record black smoke.

17

**Staff Response to Comment Letter #3:**

## Response to Comment 3-1:

Staff appreciates CBE for taking the time to comment and express concerns. Staff understands the potential health impacts resulting from $SO_2$ emissions and is proposing a lower $SO_2$ performance target of 0.25 ton per processing capacity which is estimated to achieve 51 percent reduction in $SO_2$ emissions from flaring in WCWLB community. This level of reduction in $SO_2$ emissions from flaring will make a positive impact on the air quality for surrounding communities and will result in concurrent reductions in other pollutants such as VOC and NOx, and thus further mitigation of health impacts. Staff's proposal to reduce the $SO_2$ performance target was driven by the AB 617 WCWLB CERP objectives and staff's technical feasibility evaluation for all facilities. An essential piece of the AB 617 program is the partnership and collaboration with the community to ensure that the CERP addressed the community's air quality priorities. The CERP is a critical part of implementing the AB 617 program and seeks to address the identified objectives through actions that reduce air pollution within the local community. The CERP was developed in conjunction with the Community Steering Committee (CSC) whose members consist of people who live and work within the community. CSC members provide their guidance and insight to be incorporated into the development of the CERP objectives. One of the main objectives of CERP for this community was to reduce $SO_2$ emissions from flaring by 50 percent which staff aimed to satisfy. However, staff also evaluated the technical feasibility to reduce the $SO_2$ performance beyond the established targets in CERP – staff evaluated the feasibility to further reduce the $SO_2$ performance target by 80% which is equivalent to a performance target of 0.1 ton of $SO_2$ per processing capacity. However, upon further evaluation of the facilities configuration and logistics that have consistently achieved a target of 0.1 ton of $SO_2$, staff concluded the lower $SO_2$ target was not cost effective. The facilities achieving the $SO_2$ performance target of 0.1 ton per processing capacity are equipped with multiple gas turbine cogeneration units and large flare gas recovery system capable of diverting the recovered vent gas that would be sent to the flare system. Staff's evaluation concluded that the cost to consistently achieve the 0.1 ton of $SO_2$ per processing capacity is not cost-effective due to the high cost of controls (please see Chapter 3 of staff report regarding staff's evaluation). However, the $SO_2$ performance target of 0.25 ton per processing capacity can be achieved by minimizing the volume of vent gases routed to the flare by designing and implementing flare minimization projects which does not necessarily require adding new control equipment. In order to stay below the proposed $SO_2$ performance target, facilities will need to reevaluate existing process and equipment operating procedures or practices.

Staff does not agree with CBE's suggestion for accelerating the timeline. Some facilities may only require changes to their operational practices and procedures while other facilities may elect to do flare minimization projects, which will require submittal of a permit application for a new project and modification of the facility's flare monitoring and recording plan, all of which will need to be reviewed and approved by South Coast AQMD before the policies, procedures, or projects can be implemented.

## Response to Comment 3-2:

Staff's proposal to reduce the $SO_2$ performance target from 0.5 to 0.25 ton per processing capacity (MMbbl) will concurrently reduce both VOC and NOx emissions by reducing the overall volume of vent gas going to the flare. The South Coast region is classified as extreme non-attainment for ozone, so all efforts must be taken to reduce the precursors of smog formation. Staff is aware of the contribution of VOC to ozone; however, NOx is the main driver for ozone or smog within the region which is why South Coast AQMD has undertaken rigorous rulemaking efforts to reduce regional NOx emissions. Rule 1109.1 was adopted on November 5, 2021, and established one of the nation's most stringent NOx standards for refinery equipment and is anticipated to reduce over 1,600 tons of NOx annually in the WCWLB communities; this large reduction in NOx emissions is a significant step towards achieving attainment for ozone and improving public health. Staff does acknowledge that there were a few flare events which were higher in terms of VOC emissions when compared to $SO_2$, but staff's evaluation of flare emissions over a 12-year time span showed a large portion of the flaring events were driven by $SO_2$ emissions, rather than ~~not~~ VOC emissions. The performance targets are based on annual emissions, so even though individual flare events occur with higher VOC emissions than $SO_2$; historically, annual $SO_2$ emissions are higher than annual VOC emissions.

According to the chart presented in the comment letter, VOC associated flaring were trending downwards between 2007 through 2016 which is consistent with staff's evaluation of historical flaring data. However, the statement that flaring emissions are trending upwards in recent years may be misleading. As CBE noted prior in the comment letter, the 2017 amendments to the rule increased the VOC emissions factor by approximate factor of 10 which explains the large increase from 2017 to 2022. The increase does not necessarily constitute an increase in VOC driven flaring emissions due to update of the VOC emission factor. A majority of the time, $SO_2$ and VOC emissions go hand in hand with each other, so reducing overall volume of vent gas to the flare through establishing a lower $SO_2$ performance target will also reduce the VOC emissions by an equivalent ratio.

**Response to Comment 3-3:**

Facilities are required to submit a flare minimization plan (FMP) when they exceed their facility specific annual performance target. As part of the amendment, staff is proposing to lower the $SO_2$ performance target for general service flares, establish a new NOx performance target for hydrogen clean service flares, and establish a new throughput threshold for LPG flares. These new and lower requirements will increase the number of FMP the facilities must submit. Therefore, maintaining and improving equipment reliability to prevent repeated malfunctions or breakdowns will be in the best interest of each facility. The lowering and inclusion of new requirements will force facilities to review their operation and procedures more frequently. FMPs are submitted to South Coast AQMD for a specific flare event and evaluated on a case-by-case basis that must be supported with sufficient data.

All breakdowns at a facility are subject to the breakdown provisions in Rule 430 which requires the facility to notify South Coast AQMD within one hour of the breakdown occurrence. As part of the breakdown process, a facility must identify the time, specific location, equipment involved, and the cause of the breakdown. Most importantly the facility must also provide information substantiating that the breakdown did not result from operator error, neglect or improper operation or maintenance procedures. Repeated malfunctions of the same equipment are not considered breakdowns.

Staff agrees with the comment that fees should be increased and is proposing to adjust mitigations fees in accordance with consumer price index (CPI). The increase in mitigation fees will serve as a deterrent and encourage facilities to evaluate options for reducing flaring.

## Response to Comment 3-4:

Staff initially proposed requiring facilities to post real-time video feed on FENS or another public webpage, but concerns were raised regarding potential security breaches. Safety and security concerns in the refining industry are of great importance and a risk that South Coast AQMD cannot disregard. Refiners currently must comply with other existing regulations such as:

- Chemical Facility Anti-Terrorism Standards (CFATS) administered by Homeland Security
- Infrastructure Security Agency (CISA)
- U.S. Coast Guard (Maritime Law).

Facilities have been increasingly focusing their attention to cyber-security treats, especially when it relates to critical process control networks and safety systems. Process control intrusions of a refinery's distributed control systems is a valid concern in today's technological age. The distributed control systems play an important role in monitoring and controlling the process and operation of the entire facility. In addition, most refiners also operate a safety instrument system and is typically the final line of defense against equipment failures. Equipment failures can result in process events that can escalate into a situation that endangers the plant, personnel, and surrounding communities, so facilities must adhere to strict security guidelines.

South Cost AQMD has an inspections team dedicated to the refineries 24/7 with a satellite office nearby. Inspectors follow up immediately, or in a timely manner, to assess flare events and take enforcement action if necessary. Inspectors have access to the flare videos and can view them at any time during the investigation to determine if the smokeless capacity for a flare event has been exceeded. In addition, a new requirement for reporting smokeless capacity exceedance is now included in the rule allowing the inspector to initiate further follow up action to determine if a violation occurred. Staff also disagrees that continuous monitoring with online access is a key tool for improving emissions performance since all facilities are currently required to monitor the flare for visible emissions using color video monitors capable of video recording. Further, the flare events are not being hidden from the community as flares are elevated and visible such that anyone in the nearby community has the ability to observe them when they occur.

## Response to Comment 3-5:

Staff agrees that controlling emissions from clean service flares is long overdue and continual flaring is not essential and  results in unnecessary emissions. Staff also agrees that the term "clean service flare" does not mean the flares do not emit any pollutants; it only refers to the lack of sulfur present in the gas stream. To minimize the impacts to surrounding communities, staff proposed two new requirements for the clean service flares that include an annual throughput limit for the LPG flares and a NOx performance target for flares at hydrogen production plant. Both requirements will require facilities to install control equipment or evaluate current operating practices or procedures to stay below the applicable limit or target. Staff will monitor and re-evaluate all of the performance targets and their impacts on emissions the next time a major amendment to Rule 1118 is considered. Staff proposed a feasible NOx performance target based on operational variability of the hydrogen plant flares and evaluated all potential options for controlling the flare emissions. To achieve a lower NOx target for the flares, the facilities would need to install a gas turbine with vapor recovery system which was determined infeasible at the moment based on the cost-effectiveness analysis. Furthermore, if potential expansion at hydrogen production plants were to occur, the facilities would be regulated under Rule 1109.1 which regulates NOx emissions from refinery and refinery-related equipment. The NOx emissions from hydrogen production plants are primarily from the steam methane reformer heaters, which is a specific type of heater used at hydrogen production plants to generate hydrogen. Steam methane reformer heaters must comply with a stringent NOx limit of 5 ppmv. If there is an increased production at hydrogen plants, the NOx emissions from the steam methane reformer heater will be controlled by Rule 1109.1 and the flare emissions will be limited through the performance target in Rule 1118.

## Response to Comment 3-6:

The composition of gas burned in clean service flares are typically gases with fixed composition and the heat content of the gas is usually predictable regardless of flaring situations. In contrast, the vent gas burned in a general service flare can vary considerably due to the potential sources going to the flare, so a conservative or higher emission factor makes sense in those flaring situations. The 2017 amendment updated the emission factors for vent gas based on U.S. EPA's revision of its Air Pollution Emission Factors (AP-42) guidance for estimating volatile organic compound (VOC) emissions from flaring events. The updated AP-42 emission factor for VOC emissions was increased about 10-fold (from 0.063 to 0.66 pound of VOC per million British thermal units or lb/MMBtu).

Staff disagrees with the statement that the lower VOC emission factor undermines the cost-effectiveness calculation. Staff's cost-effectiveness analysis concluded that reducing flaring emissions from the LPG flare through installation of controls is cost-effective and is based on reduction in NOx emissions and not VOC. The emission factor for NOx is much higher than the VOC emission factor for propane and butane. There is no need to recalculate the cost-effectiveness for the LPG clean service flares using a VOC emission factor since the cost-effectiveness was well below the $349,000 per ton threshold for NOx.

## Response to Comment 3-7:

To clarify, staff supports the use of the flare remote sensing technology for the purpose of flare emissions characterization. Staff met with a technology vendor (i.e., Providence Photonics) and U.S. EPA several times to obtain a better understanding of the technology and data verification process of the technology. Based on the information provided to staff, the remote sensing technology does show promise, but is not an approved method at this time. U.S. EPA has purchased several units for further testing and verification. Staff will continue to follow-up with both Providence Photonics and U.S. EPA regarding the technology. However, staff determined the technology as infeasible at this time, because the verification and test method has not been officially approved by U.S. EPA. South Coast AQMD alone is not given unbounded sole discretion when establishing and approving a test method. In fact, Rule 1118 was amended on January 6, 2023, to address a partial disapproval by U.S. EPA. The amendment required modification to an existing provision so that any ASTM standards not currently listed in the rule must be approved by CARB and U.S. EPA, along with approval by the Executive Officer.

## Response to Comment 3-8:

The current definition of Essential Operational Need (EON) is pre-defined and very specific to disqualify many scenarios that a facility could identify as an EON. As part of the amendments to Rule 1118 in 2005, for the definition of EON, staff carefully analyzed which specific operations are essential and may not be reasonably controlled by the facilities. The definition is clearly delineated to avoid any confusion as to what would constitute an EON. BAAQMD's Regulation 12-12 states "*This standard shall not apply if the APCO determines, based on an analysis conducted in accordance with Section 12-12-406, that the flaring is caused by an emergency and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere.*" The definition is not present because it is not clearly defined and based upon an analysis conducted by the APCO which is determined on a case-by-case basis.

**Response to Comment 3-9:**

Thank you for the suggestion regarding the upgrade to FENS and appreciates the early engagement. Staff will work closely with all stakeholders through a public process to ensure most concerns are incorporated into the future FENS update. Staff agrees that flaring data should be easily accessible in a clear format. Staff looks forward to working with all stakeholders in upgrading the features in FENS.

**Response to Comment 3-10:**

For comment 3-10-1, please see comment 3-1

For comment 3-10-2, please see comment 3-2

For comment 3-10-3, please see comment 3-3

For comment 3-10-4, please see comment 3-4

For comment 3-10-5, please see comment 3-7

For comment 3-10-6, please see comment 3-5, comment 3-6, comment 3-8, and comment 3-9

Thank you.

**Response to Comment 3-11:**

Thank you for your comment. Staff really appreciates the perspective and engagement from the youth and future leaders of the community. Staff understands that flares can evoke a feeling of fear and confusion due to their large visible nature and is the reason why staff seeks the most stringent regulation feasible allowed under California Health and Safety Code. Staff analyzes all reasonably available control measures and technology when developing regulations to ensure protection of public health; staff's evaluations and proposals are within the specified criteria of demonstrating technical feasibility and cost-effectiveness. Again, staff thanks the young members of the community for taking time to voice their concerns.

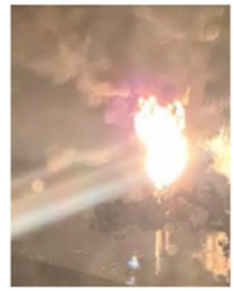
## *Comment Letter #4*

Feb. 22, 2024

South Coast Air Quality Management District (AQMD)

**Re: Rule 1118 - Earlier progress cutting harmful oil refinery flaring emissions has stagnated and even reversed; the proposed regulation is still missing key tools**

Dear AQMD Governing Board and Staff,



*2/9/2024, Phillips 66, Wilm. CA, Ashley Hernandez, CBE*

**After many decades of regulatory work since earlier years of unbridled flaring, refinery flares still regularly emit large and even increasing volumes of harmful gases.**

The flare regulation has been updated multiple times, so we are not starting from scratch, and can do much better. After considerable staff work and years of promises, we need adoption of *all readily available controls* (listed next page). The photo at right just this month illustrates the massive flames and smoke adding large burdens to already-compromised air quality in refinery neighborhoods. Black, brown, indigenous, and people of color communities are hit hardest by refinery flaring.

**Other recent-year examples include one flaring event emitting 65,000 lbs. of Sulfur Oxides (SOX) and another at 43,000 lbs. of Volatile Organic Compounds (VOCs) in Wilmington.**[1] Every year, many flaring events *each* emit thousands of pounds of pollutants near all the refineries.

*What causes flaring?* Gases are sent to flares to prevent dumping the most hazardous directly to the air, during unplanned shutdowns when refinery equipment breaks down, or during planned shutdowns for maintenance. (Routine flaring may also occur if refineries don't have sufficient compressors and gas recycling inside the refinery, and this can be illegal.[2]) Even if 98% or higher of VOCs are combusted as assumed (becoming carbon dioxide and water), the remaining 2% or less emitted to the air equals thousands of pounds of VOCs, because gas volumes are so large. Combusted sulfur compounds like Hydrogen Sulfide are only transformed into other harmful sulfur compounds—Sulfur Oxides. (The sulfur element isn't destroyed). If flares are overwhelmed, black smoke particulate matter is also emitted. Many other pollutants are emitted.

**District staff found refineries steadily *increased* the number of unplanned breakdown flaring from 2020-2023.**[3] Many regulatory agencies found refinery accidents occur due to poor maintenance. During emergencies it is too late to avoid flaring – these must be prevented ahead of time.

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[1] Through Public Records Act requests, CBE received 2020-2022 flare data measured pursuant to Rule 1118, reported to SCAQMD. On 6/1 to 6/2/2020 Valero flares emitted >65,000 lbs SOx and 1/22 to 3/4/2022 emitted > 43,000 lbs. VOCs.

[2] U.S. EPA Enforcement Alert*: Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases Practice Not Considered 'Good Pollution Control Practice'; May Violate Clean Air Act*, 2000, https://www.epa.gov/sites/default/files/documents/flaring.pdf

[3] SCAQMD draft staff report, Jan. 2024, p. 2-12, **unplanned flaring events increased steadily from 129 in 2020 to 232 in 2023**.

We urge the following improvements to the draft regulation (and moving adoption to at least May):

1) **The proposed 2028 <u>Annual SOx emission target</u> is so loose, most refineries already met far tighter standards years ago.** It acts like a backstop, not an achievable improvement. 4-1
   - *Tighten to <<u>0.10</u> tons SOx per million barrels crude oil processed, which has already been met by multiple refineries (instead of <u>0.25</u>, a step backward[4]).*
2) **An <u>Annual VOC target is entirely missing</u>** – there is *no* such standard to address high-VOC, low-SOx events missed by the annual SOx target. 4-2
   - *Set a similar achievably low VOC target, based on long-term flare data, since such targets for SOX were found effective by the staff.*
3) **<u>Flare Minimization Plans are not required every year</u>** 4-3
   - *Require annually, ensure they plan to prevent causes of large flaring of previous years.*
4) **<u>The oil industry killed staff-proposed</u> <u>Online Video Monitoring which could document harmful *smoking* flare violations</u>** that would otherwise be missed by AQMD enforcement. Vague Homeland Security arguments were used by the industry, reminiscent of South African censorship during Apartheid (when refinery emissions were defined as official state secrets). This is absurd—neighbors can see and film flaring, but District staff must travel long distances, frequently arriving too late to see and enforce against smoking flare violations, unless staff has access to realtime flare video. 4-4
   - *Reinstate staff-proposed realtime online flare video monitoring.*

***July 11, 2023*** *- Phillips 66, photo provided to Alicia Rivera, CBE, by CBE member*

5) **<u>The District promised in 2017 to carry out specialized Remote Optical Sensing of flares</u>** to improve emissions understimations, but now says communities must wait until EPA develops its test protocol (though the District has many of its own protocols). 4-5
   - *Commit to Remote Sensing by a date certain (within 3 years).*
6) **<u>Other key amendments are needed</u>** including correcting low-ball VOC calculations (inconsistent with EPA), more comprehensive prevention of constant flaring at hydrogen and so-called "Clean Service" flares, definition loopholes, etc. Additional technical details are included in comments submitted by Communities for a Better Environment (CBE). 4-6

We applaud the excellent work done in the Staff Report and the analysis by staff. However, compromises have been won by the oil industry which keep the flare regulation from minimizing

[4] According to the SCAQMD Reg. 1118 staff report, *Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares January 2024*, Table 3-3, p.3-3. **Marathon Carson achieved 0.10 tons SOx /million barrels crude every year since 2012** (and average less than 0.03 tons/million barrels, never higher than 0.08.) Since 2017 Chevron El Segundo achieved 0.10 tons SOx 3 out of 5 years (and close to that in 2012 and 2016). From 2013-2016 Marathon Wilmington achieved it (as well as 2018 and 2020). TORC achieved it in 2021 and was close to achieving it in 2020. Only Phillips 66 failed to achieve 0.10 since 2012. **It is a step backward to set the standard now at 0.25 tons SOx/million barrels crude processed.**

flaring to readily-achievable levels. Minimizing flaring also requires accident prevention, which saves refineries money. Unlike other regulations, most methods for minimizing flaring don't require adding control equipment, just better refinery operation to prevent malfunctions, which is more cost-effective than frequent breakdowns.

Communities also deserve well-maintained and run refineries using good pollution control practices. Repeated and unnecessary flaring is paid for in community health risks due to hundreds of thousands of pounds each year of pollutants from flaring.

Thanks for your consideration.

Sincerely;

Ashley Hernandez, Wilmington Youth Organizer and
Julia May, Senior Scientist, Communities for a Better Environment (CBE)

Oscar Espino-Padron, Senior Attorney, Earthjustice

Jane Williams, Executive Director, California Communities Against Toxics

Jesse N Marquez, Executive Director, Coalition For A Safe Environment

Taylor Thomas, Eastyard Communities for Environmental Justice

**Staff Response to Comment Letter #4:**

**Response to Comment 4-1**

Please see response to comment 3-1

**Response to Comment 4-2**

Please see response to comment 3-2

**Response to Comment 4-3**

Please see response to comment 3-3

**Response to Comment 4-4**

Please see response to comment 3-4

**Response to Comment 4-5**

Please see response to comment 3-7

**Response to Comment 4-6**

Please see response to comments 3-5, response to comment 3-6, and response to comment 3-8

**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 1118 – CONTROL OF EMISSIONS FROM REFINERY FLARES**

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 1118 – Control of Emissions from Refinery Flares

**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 1118 contains requirements for flares operated at petroleum refineries and related operations, including requirements to submit notifications and reports, monitor emissions, meet emissions targets, and maintain a public inquiry hotline. Proposed Amended Rule (PAR) 1118 utilizes the information gathered from the previous amendments in 2017 and proposes to establish: 1) a more stringent annual sulfur dioxide (SO2) performance target threshold for all facilities which will reduce emissions of sulfur oxides (SOx); 2) a new annual nitrogen oxides (NOx) performance target for clean service flares at hydrogen production plants; 3) new requirements for clean service flares at refineries (e.g., flares for liquified petroleum gas tanks); 4) an adjustment to mitigation fees annually based on the most recent consumer price index; and 5) updated and standardized reporting requirements for facilities through the flare event notification system. Finally, PAR 1118 removes outdated rule language and reorganizes the rule structure to ensure consistency with recently amended or adopted rules. PAR 1118 will be applicable to 12 facilities with 31 flares, and to comply with PAR 1118 requirements, installations of the following are expected: 1) continuous flow meters (CFMs) on three flares; 2) one refrigeration/chiller for one flare; and 3) replacement of an existing flare system with one new flare system. Implementation of PAR 1118 is expected to result in emission reductions of 10.1 tons per year of NOx, 16.6 tons per year of SO2 and 3.8 tons per year of VOC by 2029 which will benefit public health and ambient air quality. In addition, SO2 is a precursor to the formation of PM2.5; therefore, the SO2 emission reductions will result in approximately 3.3 tons of PM2.5 reduced per year.

| | |
|---|---|
| **Public Agency Approving Project:**<br>South Coast Air Quality Management District | **Agency Carrying Out Project:**<br>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 1118) 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 the proposed project indicates that the construction activities and associated emissions are expected to be minimal. Thus, 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: April 5, 2024

| **CEQA Contact Person:** | **Phone Number:** | **Email:** | **Fax:** |
|---|---|---|---|
| Jivar Afshar | (909) 396-2040 | jafshar@aqmd.gov | (909) 396-3982 |
| **PAR 1118 Contact Person:** | **Phone Number:** | **Email:** | **Fax:** |
| Zoya Banan | (909) 396-2332 | zbanan@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 AQMD

# Proposed Amended Rule 1118: Control of Emissions from Refinery Flares

BOARD MEETING

APRIL 5, 2024

ATTACHMENT I

# Background

## Rule 1118 was adopted on February 13, 1998

- Objective is to control and minimize emissions from refinery flares
- Last major amendment in 2017 was phase one of a two-phase amendment focused on data collection

## Proposed Amended Rule 1118 is necessary to

- Implement the second phase of the two-phased amendment to reduce emissions
- Fulfill air quality objectives in Assembly Bill 617 (AB 617) Wilmington, Carson, West Long Beach (WCWLB) Community Emissions Reduction Plan (CERP)

# Public Process

PAR 1118

- Five Working Group Meetings – Starting July 2022
- 35+ Meetings with Stakeholders Including Industry, Environmental, and Community Groups
- Site Visits to Each Regulated Facility
- One Public Workshop
- One Community Focused Meeting with Wilmington, Carson, West Long Beach Communities

# Key Proposed Rule Requirements

### Lower $SO_2$ Performance Target

0.5 to 0.25 tons per million barrels

50% $SO_2$ emission reduction

### New NOx Performance Target

0.3 pounds per million standard cubic feet for hydrogen plants flares

### New Annual Throughput Limit

15,000 million Btu per year for non-hydrogen clean service flares

### Increased Mitigation Fees

Mitigation Fees increased and tied to annual consumer price index

** All proposals aligned with AB 617 CERP objectives for WCWLB community*

# Overview of Emission Reductions and CERP Targets

| Pollutant | All Facilities (Total) | | | Wilmington, Carson, West Long Beach Facilities | | | |
|---|---|---|---|---|---|---|---|
| | Baseline Emissions[1] (tpy[2]) | Reductions (tpy) | Reductions (%) | Baseline Emissions (tpy) | Reductions (tpy) | Reductions (%) | CERP Emission Reductions Target by 2030 (tpy) |
| $SO_2$[3] | 55.0 | 16.6 | 30 | 27.3 | 13.8 | 51 | 11 |
| VOC | 20.7 | 3.8 | 18 | 16.7 | 3.8 | 23 | 1 |
| NOx | 14.7 | 10.1 | 69 | 11.0 | 9.8 | 89 | 19[4] |

(1) *Baseline year is 2017 for $SO_2$ and NOx and 2019 for VOC*
(2) *Tons per year (tpy)*
(3) *$SO_2$ is a precursor to PM, reductions in $SO_2$ will generate a reduction of ~ 3.3 tpy of PM*
(4) *NOx reductions primarily achieved through Rule 1109.1 (~1,600 tpy in WCWLB community)*

# Other Key Proposed Amendments to Rule 1118

- Clarify and restructure rule language
- Update requirements for notifications sent through the online Flare Event Notification System
- Require standardized flare event data reporting to allow emissions data to be publicly released in a timely manner
- Add references to Federal Refinery Sector Rule to clarify rule provisions

# Key Issues #1

- Stakeholders requested a lower $SO_2$ performance target of 0.1 tons of processing capacity

- Staff evaluated performance target of 0.1 ton per processing capacity
  - Achieved with installation of multiple gas turbine cogeneration units to divert flare gas
  - Not cost-effective for refineries to install gas turbine cogeneration units
    - $1.6 million per ton of $SO_2$ reduced
- Proposal to lower the $SO_2$ performance target from 0.5 to 0.25 ton per processing capacity will:
  - Require actions (e.g., replace equipment, process changes, increase efficiency) that are cost effective to *consistently* meet 0.25 tons target
  - Achieve 50 percent $SO_2$ emission reduction
    - Fulfills WCWLB CERP objective
    - Co-benefit of VOC emission reductions

# Key Issues #2

- Stakeholders requested the inclusion of a VOC performance target

- Flares required to have a VOC destruction efficiency of 98 percent
- VOC reductions will be achieved through:
  - $SO_2$ performance target (for all flares)
  - New throughput limit (for flares combusting liquid petroleum gas)
- Total VOC reductions of 3.8 tons per year from new rule provisions

# Staff Recommendations

Adopt Resolution:

- Determining that PAR 1118 is exempt from the requirements of the California Environmental Quality Act

and

- Amending Rule 1118

Image Courtesy: POLITICO