BOARD MEETING DATE: July 7, 2017 AGENDA NO. 38

PROPOSAL: Determine That Proposed Amendments to Rule 1118 – Control of Emissions from Refinery Flares Are Exempt from CEQA; Amend Rule 1118; and Transfer and Appropriate Funding

SYNOPSIS: Refineries are required to minimize their flaring under Rule 1118. Recent significant flaring events at some local refineries have shown that additional actions are needed to further reduce flaring emissions. PAR 1118 will incorporate parts of U.S. EPA's recently updated Refinery Sector Rule that prohibits the frequency of certain flaring events. PAR 1118 will also require facilities to prepare a Scoping Document to evaluate the feasibility of reducing or avoiding flaring events, update emission factors based on recent U.S. EPA guidance, remove the annual cap on mitigation fees paid for flaring, enhance current reporting requirements, and other administrative updates. This action would also transfer and appropriate $100,000 from the Rule 1118 Mitigation Fund (54) to Informations Managements's FY 2017-18 Budget to update the web-based Flare Event Notification system.

COMMITTEE: Stationary Source, May 19 and June 16, 2017, Reviewed

RECOMMENDED ACTIONS:
Adopt the attached resolution:

1. Determining that the proposed amendments to Rule 1118 – Control of Emissions from Refinery Flares, are exempt from CEQA;
2. Amending Rule 1118 – Control of Emissions from Refinery Flares; and
3. Transfering and appropriating up to $100,000 from the Rule 1118 Mitigation Fund (54) to Information Management's FY 2017-18 Budget (Org 27), Capital Outlays Major Object to amend a contract with a Board-approved software development contractor for the update of the web-based Flare Event Notification system.

Wayne Nastri
Executive Officer

PF:SN:IM:DM

Background

Several incidents at some refineries in recent years, including offsite power disruptions and onsite process unit breakdowns, resulted in flaring events and increased emissions. These recent significant flaring events have resulted in increased public concern over the potential air quality impact of flaring emissions. Emergency flaring activities are conducted as a safety measure to relieve pressure in process units that are temporarily not operating within design parameters. Flaring also commonly occurs through routine activities such as planned start-ups/shut-downs of process units and facility turnarounds.

Rule 1118 was last amended in 2005 and includes many requirements for refineries and related facilities such as hydrogen plants and sulfur recovery plants to control, monitor, and report their flaring emissions. Key provisions in the rule include visible emissions limits, limits on the types of activities that can lead to flaring, and an annual Performance Target of 0.5 tons of sulfur dioxide (SO2) emissions per million barrels of a facility’s crude processing capacity. If a facility exceeds the Performance Target, it must pay mitigation fees and must also submit a Flare Minimization Plan to show what corrective actions they will take to avoid exceeding the Performance Target in the future. Facilities must also monitor the vent gases going into a flare, provide quarterly reports of their flaring emissions, and notify the SCAQMD if a flare event’s emissions exceed thresholds. These requirements and the subsequent actions that refineries have taken to meet them have led to substantial reductions in flaring over the years. However, thousands of minor flaring events still occur every year, along with much more infrequent but significant events.

Between 2012-2016, facilities reported 1,179 tons of SOx emissions, a key pollutant from flaring. These SOx emissions from flaring represent about 3% of the total air basin SOx emissions. Except for a few significant flaring events that occurred at the ExxonMobil refinery (now Torrance Refinery) that are being addressed in part through a Stipulated Order for Abatement through the SCAQMD Hearing Board, about two-thirds of SOx emissions come from planned activities, such as process unit start-ups/shut-downs and venting of gas streams that are not compatible with the refinery fuel gas systems. The remaining SOx emissions occur during emergency events such as power outages or unplanned process unit shut-downs. Although SOx is commonly used as a metric for evaluating flaring emissions, other pollutants are emitted from this process, including volatile organic compounds (VOCs), particulate matter (PM), and some toxic air contaminants such as benzene, formaldehyde, and other hydrocarbons.

Recent federal actions have established new methods to control flaring emissions and have adopted new methods to evaluate flaring emissions. In December 2015, U.S. EPA approved a significant update to its Refinery Sector Rules for refinery process units and ancillary equipment operations, including flare operations. The updated federal requirements for flaring focused on reducing significant flaring events, and ensuring that when flaring does occur, combustion is as efficient as possible in order to reduce emissions. In addition, based on recent studies, in December 2016 U.S. EPA revised its AP-42 (U.S. EPA's compilation of air pollutant emission factors) guidance for estimating VOC emissions from flaring, increasing the emission factor about ten-fold.

Proposal

SCAQMD staff is proposing to amend Rule 1118 in two phases. The current proposed amendments included in this Board package represent the first phase, while the second phase of rulemaking is expected to begin in 2018. Information collected from implementation of Proposed Amended Rule 1118 (the first phase) will be used to inform the second phase of rulemaking. The Proposed Amended Rule incorporates some provisions from the U.S. EPA's Refinery Sector Rule, as detailed below.

U.S. EPA's Refinery Sector Rule

Proposed Amended Rule 1118 incorporates U.S. EPA's Refinery Sector Rule provision which establishes: a new limit on the heating value of flare gases in the combustion zone and flare tip velocity limits (measures designed to promote more efficient combustion), incorporation by reference of flare monitoring requirements that will supplement existing Rule 1118 monitoring requirements, and three new prohibitions of flaring events above the smokeless capacity of the flare that also exceed visibility or flare tip velocity limits in any of the three cases below:

- Three times in any three-year period, with the flaring events occurring from any cause.
- Two times in any three-year period, with the flaring events having the same root cause.
- One time, if the flaring event was caused by operator error or poor maintenance.

Facilities will need to comply with these new requirements in Proposed Amended Rule 1118 starting January 2019 , the same schedule as the U.S. EPA Refinery Secion Rule. Due to the complexity of the U.S. EPA Refinery Sector Rule, only the most significant portions are being incorporated with the current proposed amendments. The remainder of the U.S. EPA Refinery Sector Rule will be fully incorporated in the second proposed phase of rulemaking.

Removal of the $4 Million Annual Mitigation Fee Cap for Flaring

Proposed Amended Rule 1118 will remove the $4 million annual mitigation fee cap for flaring to provide a stronger incentive to facilities to minimize flaring, particularly for facilities that have had multiple events within a year. The mitigation fee cap has been reached two times, both times by the same facility. Facilities would be required to pay into the 1118 Mitigation Fund for all of the emissions that exceed the annual performance target.

Scoping Document to Reduce Flaring Events

Under Proposed Amended Rule 1118, facilities would be required to prepare a scoping document that evaluates the feasibility of reducing or avoiding planned and unplanned flaring events. Rule 1118 currently establishes a Performance Target of 0.5 tons of SOx per million barrels of crude refining capacity. The proposed amended rule requires facilities to evaluate the feasibility of potentially reducing emissions from planned flare events to 0.10, 0.05, and 0.01 or lower tons of SOx per million barrels of crude processing capacity and 0.1 tons per year of VOC from clean service flares. In addition, for emergency flare events, facilities must evaluate the feasibility of installing and maintaining three physical systems or automated process controls that can be used to avoid or minimize flaring. Information from the scoping documents will be used in the second phase of rulemaking.

Notification Requirements and Funding to Upgrade Web-based Notification System

Under Rule 1118, facilities currently notify the District using both a telephone and an older web-based notification system. The proposed amended rule lowers the notification level when facilities would be required to notify the District about flaring events and also requires all notifications via a web interface. In order to accommodate this new requirement, the existing web-based notification system must be upgraded. Staff is recommending that the Board authorize the Executive Officer to transfer up to $100,000 from the existing 1118 Mitigation Fund to the General Fund to use one of the previously Board-approved software development contractors to update the web notification system. This update will automatically notify SCAQMD staff of flaring events and automatically send email notifications to the community for flare events above public notification thresholds. This funding item is not included in the Fiscal Year 2017-18 budget, but sufficient funding is available in the 1118 Mitigation Fund to cover this request, and the requested funding is consistent with the limited uses allowed for this fund.

Update Flaring Emission Factors & Administrative Changes

Proposed Amended Rule 1118 will also update the flaring emission factors based on U.S. EPA’s updated AP-42 guidance to make the rule consistent with U.S. EPA guidance, a key factor as the rule is included in the State Implementation Plan (SIP). Updating the flaring emission factor will increase VOC emissions estimates by about a factor of ten for refinery vent gases, and about a factor of three for propane and butane flaring. The administrative updates will remove outdated parts of the rule, such as compliance phase-in schedules that have already been achieved.

Public Process

Proposed Amended Rule 1118 was developed with input from a stakeholder working group that included representatives from industry, environmental groups, community groups, and public agencies. Four working group meetings were held on: February 28, 2017, March 22, 2017, April 27, 2017, and May 30, 2017. To facilitate community input, the March working group meeting was held in Torrance and the April working group meeting was held in Wilmington. A Public Workshop was held on May 11, 2017 to present the proposed rule and receive public comment.

Key Issues
Through the rulemaking process, staff has been working with stakeholders and has resolved a number of issues such as removing potential conflicts with the U.S. EPA Refinery Sector Rule, simplifying notification requirements, and providing specific criteria for the Scoping Documents. Stakeholders have expressed concerns about two remaining issues: 1) the VOC emission factor for propane/butane flares; and 2) the VOC threshold for notifications and Specific Cause Analyses.

Regarding the first issue, some community representatives have commented that the proposed VOC emission factor for clean service flares is too low and the emission factor for vent gases should be used instead. Staff is recommending that the proposed amendments be retained because the emission factor for vent gases (which will be increasing 10-fold under PAR 1118) is based on testing conducted on gases of a different composition (e.g., propylene) compared with testing of pure propane or butane streams used in clean service flares. As part of the Optical Remote Sensing study, considered as a separate Board item, staff will investigate if additional emissions data from propane/butane flaring can be obtained from those new monitoring techniques, and will report back to the Stationary Source Committee as that study progresses.

Regarding the second issue, some industry representatives have expressed concerns that because the VOC emission factor for vent gases is increasing approximately ten-fold, the 100 pound threshold for notifications and Specific Cause Analyses should be increased accordingly. Some industry representatives have commented that maintaining the 100 pound threshold will result in many more notifications and Specific Cause Analyses. Conversely, environmental groups have stated that the 100 pound threshold should be retained at its current level as this has been the accepted threshold for notification and Specific Cause Analyses. Staff is proposing to maintain the threshold at 100 pounds as this would be consistent with previous Board decisions and the potential increased workload for facilities and SCAQMD staff is not overly burdensome. Retaining the 100 pound threshold with the ten-fold increase in the VOC emission factor may increase notifications from about 3 to 7 per week and Specific Cause Analyses from about 2 to 3 per week, spread across all facilities.

California Environmental Quality Act
Pursuant to the California Environmental Quality Act (CEQA) and SCAQMD Rule 110, the SCAQMD, as lead agency for the proposed project, has reviewed the proposed amendments to Rule 1118 pursuant to: 1) CEQA Guidelines § 15002(k) - General Concepts, the three-step process for deciding which document to prepare for a project subject to CEQA; and 2) CEQA Guidelines § 15061 - Review for Exemption, the procedures for determining if a project is exempt from CEQA. SCAQMD staff has determined that the project is exempt from CEQA pursuant to CEQA Guidelines § 15306 – Information because the project consists of basic data collection and research and resource evaluation activities and will not result in a serious or major disturbance to

an environmental resource. CEQA Guidelines §15306 exempts such a project for information-gathering purposes, or as part of a study leading to future action which the agency has not yet taken. Furthermore, SCAQMD staff has determined that it can be seen with certainty that there is no possibility that the proposed project may have a significant adverse effect on the environment. Thus, the project is also considered to be exempt from CEQA pursuant to CEQA Guidelines § 15061(b)(3) – Activities Covered by General Rule. A Notice of Exemption (NOE) has been prepared pursuant to CEQA Guidelines § 15062 - Notice of Exemption, and is included as an attachment to the Board package. If the project is approved, the NOE will be filed with the county clerks of Los Angeles, Orange, Riverside and San Bernardino counties.

Socioeconomic Analysis

A socioeconomic analysis was conducted for Proposed Amended Rule 1118. The amendments would lower flaring emissions and affect 12 facilities operating a total of 31 flares. Eight out of 12 facilities belong to the sector of petroleum refineries; of the remaining four, one sulfur recovery plant and three hydrogen production plants belong to the sector of industrial gas manufacturing. All the affected facilities are located in Los Angeles County and none are small businesses.

Two proposed amendments could potentially have cost impacts. Preparation of a scoping document to evaluate the feasibility of emissions reductions from planned and unplanned flaring events could potentially cost $50,000 for a non-refinery facility and $250,000 for a refinery facility. These costs are one-time in nature and would add up to about $2.2 million for all affected facilities. These Scoping Documents are necessary to identify feasible measures to further reduce emissions from flaring in a second phase of rulemaking. The removal of the $4 million annual cap on mitigation fees could potentially impose additional costs on affected facilities if their SOx emissions substantially exceed the performance target. Past performance records (2012-2016) for the 12 facilities show that only one facility in 2015 would have exceeded the $4 million cap ($7.7 million) due to an explosion which caused a shutdown and subsequent atypical operations for the remainder of the year. A second instance where a facility had a bypass valve that was unmonitored also exceeded the annual cap (this bypass valve has since been remove from service). Therefore, it is unlikely that the affected facilities would exceed the annual cap and pay more than $4 million of mitigation fees.

AQMP and Legal Mandates

Pursuant to Health & Safety Code Section 40460 (a), the SCAQMD is required to adopt an Air Quality Management Plan (AQMP) demonstrating compliance with all federal regulations and standards. The SCAQMD is required to adopt rules and regulations that carry out the objectives of the AQMP. The proposed amendments to Rule 1118 are consistent with control measure MCS-03 (Improved Start-Up, Shutdown, and Turnaround Procedures) in the 2012 AQMP.

In December 2015, the U.S. EPA issued a final rule for the Petroleum Refinery Sector Risk and Technology Review, New Source Performance Standards, and National Emission Standards for Hazardous Air Pollutants (Refinery Sector Rule) that further regulated emissions from petroleum refineries, including from flaring. PAR 1118 harmonizes some requirements for flaring with the U.S. EPA Refinery Sector Rule by explicitly including key prohibitions and operating parameters within the rule, and incorporating by reference technical calculations and monitoring requirements. In May 2015, U.S. EPA issued a final rule for State Plans to Address Emissions During Startup, Shutdown and Malfunction (SSM) to address emissions that have been exempted during startups, shutdowns, and malfunctions. The Refinery Sector Rule is consistent with the SSM rule; therefore, by harmonizing Rule 1118 with the Refinery Sector Rule, PAR 1118 will also be consistent with the SSM rule.

After adoption, the proposed rule will be forwarded to CARB and U.S. EPA for inclusion in the State Implementation Plan (SIP).

Implementation and Resource Impacts

Review of the submitted Scoping Documents may require assistance from outside consultants with expertise in refinery operations, which would require subsequent Board action. Existing SCAQMD resources will be used to implement Proposed Amended Rule 1118. Funds from the Rule 1118 Mitigation Fund (54) will support the update of the web-based Flare Event Notification System.

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 – Rule Language
G. Proposed Amended Rule 1118 – Staff Report
H. Notice of Exemption
I. Board Meeting Presentation

ATTACHMENT A
SUMMARY OF PROPOSED AMENDMENTS
Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

- ***Incorporate Portions of U.S. EPA's Refinery Sector Rule into PAR 1118***
  - Incorporates the U.S. EPA Refinery Sector Rule's (RSR) three new prohibitions on smoking flaring events that become effective January 30, 2019, that prohibit flares from operating above their smokeless capacity if they also exceed thresholds for visible emissions or flare tip velocity under any of the following events:
    - Any event caused by operator error or poor maintenance;
    - Two events at a flare in a three-year period with the same specific cause; or
    - Three events at a flare in a three-year period with any specific cause.
  - Proposed Rule 1118 requires the flare tip velocity to remain below the smokeless capacity of a flare,
  - Incorporates by reference the parts of U.S. EPA's RSR that address new monitoring requirements, and methods of calculation of certain parameters such as the net heating value of vent gas.
- ***Require Facilities to Submit Scoping Document to Evaluate Feasibility of Reducing Flaring Emissions***
  Proposed Amended Rule 1118 requires facilities to prepare a Scoping Document that evaluates the feasibility of minimizing or avoiding SOx and VOC emissions from planned and unplanned flare events.
- ***Remove Cap on Mitigation Fees***
  The current $4,000,000 annual cap on mitigation fees has been removed.
- ***Update Emission Factors***
  - Emission factors used to estimate flaring criteria pollutant emission have been updated to be consistent with updates to U.S. EPA's AP-42 guidance.
- ***Update Flare Notification Requirements***
  - Requires use of the District's web-based Flare Event Notification system for all flare notifications.
  - Requires facilities to notify the District within one hour after the cumulative daily total amount of the flare gas vented to the flare exceeds 100,000 standard cubic feet if a notification has not already been provided for that day.
- ***Remove Outdated Provisions in the Rule***
  - Removes portions of the existing rule related to alternative sampling methods.
  - Removes portions of the existing rule related to phase-in compliance dates that have already been achieved.

ATTACHMENT B
KEY ISSUES AND RESPONSES

Proposed Rule (PAR) 1118 – Control of Emissions from Refinery Flares
<u>VOC Emission Factor for Propane / Butane Flares:</u> Some community members have commented that the proposed VOC emission factor for propane and butane flares is too low, and that the higher emission factor for general vent gas should be used. Staff is recommending that the proposed amended emission factor for propane /butane be retained because it is based on test data specifically from propane / butane combustion, whereas the vent gas emission factor was based on testing gases with a different composition (e.g., propylene) that have higher emissions. <u>Threshold for Notifications and Specific Cause Analyses:</u> Industry stakeholders have commented that two changes proposed in the rule will cause a significant increase in the number of flare notifications and Specific Cause Analyses (SCAs). First, the VOC emission factor is increasing ten-fold but the VOC threshold for notifications and SCAs remains the same. Second the definition of Flare Events is changing to require that multiple events in one day from the same process unit will be grouped into a single flare event. An environmental group also commented that the existing VOC threshold should remain at the same level because this is the accepted threshold for notification and SCAs. • Staff is proposing to maintain the threshold at 100 pounds as this would be consistent with previous Board decisions and the potential increased workload for facilities and SCAQMD staff is not overly burdensome. • The proposed changes may increase notifications from about 3 to 7 per week and Specific Cause Analyses from about 2 to 3 per week, spread across all facilities. • The Flare Event definition change may increase notifications and SCAs by grouping several small flare events that are below threshold in one day into a single event that is above threshold, but it may also eliminate some SCAs by grouping larger flare events that are already above threshold into a single event. • The proposed change to the Flare Event definition will assist SCAQMD because notification will occur when multiple smaller events from the same process unit continue to occur.

ATTACHMENT C
RULE DEVELOPMENT PROCESS
Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

Beginning of Rule Development Process
October 2016

↓

Working Group Meetings
February 28, 2017 Diamond Bar
March 22, 2017 Torrance
April 27, 2017 Wilmington
May 30, 2017 Diamond Bar

↓

Public Workshop
May 11, 2017

↓

Stationary Source Committee Meetings
May 19, and June 16, 2017

↓

Set Hearing
June 2, 2017

↓

Public Hearing
July 7, 2017

10 months spent in rule development

ATTACHMENT D
KEY CONTACTS
Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

Facilities

- Alon/Paramount
- Chevron USA Inc.
- Philips 66 Wilmington
- Philips 66 Carson
- Tesoro Carson
- Tesoro Wilmington
- Tesoro Sulfur Recovery Unit
- Torrance Refinery
- Valero Refining Co.
- Air Products Carson
- Air Products Wilmington
- Air Liquide

Associations or Entities

- Western States Petroleum Association

Interested Parties

- Citizens Coalition for a Safe Community
- Communities for a Better Environment (CBE)
- Sierra Club
- Torrance Refinery Action Alliance
- Families Lobbying Against Refinery Exposures (FLARE)

ATTACHMENT E
RESOLUTION NO. 17-____
Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

A Resolution of the South Coast Air Quality Management District (SCAQMD) Governing Board determining that the proposed amendments to Rule 1118 – Control of Emissions From Refinery Flares are exempt from the requirements of the California Environmental Quality Act (CEQA).

A Resolution of the SCAQMD Governing Board amending Rule 1118 – Control of Emissions from Refinery Flares.

WHEREAS, the SCAQMD has had its regulatory program certified pursuant to Public Resources Code § 21080.5 and has conducted a CEQA review and analysis of the proposed amendments to Rule 1118 pursuant to such program (SCAQMD Rule 110); and

WHEREAS, the SCAQMD Governing Board finds and determines that the proposed amendments to Rule 1118 and the allocation of up to $100,000 from the Rule 1118 Mitigation Fund to pay for upgrades to the web-based Flare Event Notification system are considered a "project" per CEQA Guidelines § 15002(k) – General Concepts, the three-step process for deciding which document to prepare for a project subject to CEQA; and

WHEREAS, the SCAQMD Governing Board finds and determines that after conducting a review in accordance with CEQA Guidelines § 15061 – Review for Exemption, procedures for determining if a project is exempt from CEQA, the proposed project is determined to be exempt from CEQA; and

WHEREAS, the SCAQMD Governing Board finds and determines that the proposed project which consists of basic data collection, research and resource evaluation activities that will not result in a serious or major disturbance to an environmental resource, are categorically exempt from CEQA requirements pursuant to CEQA Guidelines § 15306 - Information Collection; and

WHEREAS, the SCAQMD Governing Board finds and determines that it can be seen with certainty that there is no possibility that the proposed project may have any significant effects on the environment, and is therefore exempt from CEQA pursuant to CEQA Guidelines § 15061(b)(3) – Activities Covered By General Rule; and

WHEREAS, SCAQMD staff has prepared a Notice of Exemption for the proposed project, that is completed in compliance with CEQA Guidelines § 15062 – Notice of Exemption; and

WHEREAS, the Notice of Exemption, the July 7, 2017 SCAQMD Governing Board letter, and other supporting documentation were presented to the SCAQMD Governing Board and the SCAQMD Governing Board has reviewed and considered the entirety of this information prior to approving the project; and

WHEREAS, the SCAQMD Governing Board has determined that a need exists to amend Rule 1118 to clarify requirements and provide additional enforceable mechanisms to reduce emissions of volatile organic compounds, sulfur dioxide, toxic air contaminants, and particulate matter; and

WHEREAS, the SCAQMD Governing Board obtains its authority to adopt, amend or repeal rules and regulations from California Health and Safety Code §§ 39002, 40000, 40001, 40702, 40725 through 40728, 41508, and 41700; and

WHEREAS, the SCAQMD 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 SCAQMD 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 federal or state statutes, court decisions, or state or federal regulations; and

WHEREAS, the SCAQMD Governing Board has determined that portions of Rule 1118, as proposed to be amended, incorporate explicitly or by reference some federal requirements that fall within the criteria and requirements in Health and Safety Code § 40727.2(g), and the remaining proposed amendments to Rule 1118 do not impose the same requirement as any existing state or federal regulation, and the proposed amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, the SCAQMD; and

WHEREAS, the SCAQMD Governing Board in amending Rule 1118, references the following statutes which the SCAQMD hereby implements, interprets or makes specific: Health and Safety Code §§ 40001 (rules to achieve ambient air quality standards), 40440 (a) (rules to carry out the Air Quality Management Plan), and (c) (rules which are also cost-effective and efficient), 40702 (rules to execute duties), 40910 et seq., (California Clean Air Act); and Federal Clean Air Act in 42 U.S. Code §§ 7411 (Standards of Performance for New Stationary Sources), 7412 (Hazardous Air Pollutants), and 7416 (Retention of State Authority); and

WHEREAS, the SCAQMD Governing Board has determined that there is a problem that Proposed Amended Rule 1118 will alleviate, such as flaring emissions that contribute to local and regional air pollution; additional analysis needed from facilities to determine the feasibility of reducing flaring emissions even further; outdated and inaccurate methods are being used to estimate flaring emissions; and the proposed amendments are needed to promote the attainment or maintenance of the State and Federal Ambient Air Quality Standards; and

WHEREAS, the SCAQMD Governing Board has determined that the Socioeconomic Impact Assessment of Proposed Amended Rule 1118 is consistent with the March 17, 1989 Governing Board Socioeconomic Resolution for rule adoption; and

WHEREAS, the SCAQMD Governing Board has determined that the Socioeconomic Impact Assessment, as contained in the Final Staff Report is consistent with the provisions of Health and Safety Code Sections 40440.8, 40728.5, and 40920.6; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Amended Rule 1118 will result in increased costs to the affected industries, yet are considered to be reasonable, with a total annualized cost as specified in the Socioeconomic Impact Assessment, as contained in the Final Staff Report; and

WHEREAS, the SCAQMD Governing Board has actively considered the Socioeconomic Impact Assessment and has made a good faith effort to minimize such impacts; and

WHEREAS, a public hearing has been properly noticed in accordance with the provisions of Health and Safety Code § 40725; and

WHEREAS, the SCAQMD Governing Board has held a public hearing in accordance with all provisions of law; and

WHEREAS, the SCAQMD Governing Board finds and determines, taking into consideration the factors in §(d)(4)(D) of the Governing Board Procedures (to be codified as §30.5(4)(D) of the Administrative Code), that the modifications which have been made to Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares, since the notice of public hearing was published do not significantly change the meaning of the proposed amended rule within the meaning of Health and Safety Code §40726; and

WHEREAS, the SCAQMD Governing Board has determined that the proposed amendments to Rule 1118 should be adopted for the reasons contained in the Final Staff Report; and

WHEREAS, proposed amendments to Rule 1118 are consistent with Control Measure MCS-03 (Improved Start-up, Shutdown, and Turnaround Procedures) in the 2012 AQMP; and

WHEREAS, proposed amendments to Rule 1118 will be conducted in two phases where information collected during implementation of Proposed Amended Rule 1118 will be used in the second phase are consistent with Control Measure MSC-03 (Improved Start-up, Shutdown, and Turnaround Procedures) in the 2012 AQMP; and

WHEREAS, the proposed amendments to Rule 1118 will be submitted for inclusion into the State Implementation Plan; and

WHEREAS, the proposed amendments to Rule 1118 represent the first of two phases of revisions to Rule 1118 that will proposed; and

NOW, THEREFORE, BE IT RESOLVED, that the SCAQMD Governing Board does hereby determine, pursuant to the authority granted by law, that the proposed project is exempt from CEQA pursuant to CEQA Guidelines § 15002(k) – General Concepts, § 15306 **-** Information Collection, and § 15061(b)(3) – Activities Covered By General Rule. This information was presented to the SCAQMD Governing Board, whose members reviewed, considered, and approved the information therein before acting on the proposed project; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board directs staff to provide an update to the Stationary Source Committee in the first quarter of 2019 regarding the second phase of rulemaking; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby adopt the proposed amendments to Rule 1118 pursuant to the authority granted by law as set forth in the attached and incorporated herein by reference; 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 the California Air Resources Board for approval and subsequent submittal to the U.S. Environmental Protection Agency for inclusion into the State Implementation Plan; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby direct staff to initiate a second phase of rulemaking on Rule 1118 in 2018, and no later than January 31, 2020 draft for the Board's consideration amendments to Rule 1118 that would further reduce emissions from flaring.

DATE: ___________________ ___________________________

CLERK OF THE BOARDS

ATTACHMENT F

(Adopted February 13, 1998)(Amended November 4, 2005)
(Proposed Amended Rule July 2017)

PROPOSED AMENDED RULE 1118. CONTROL OF EMISSIONS FROM REFINERY FLARES

(a) Purpose and Applicability

The purpose 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. The provisions of this rule are not intended to preempt any petroleum refinery, sulfur recovery plant and 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) Definitions

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

~~(1) CLEAN SERVICE FLARE is a flare that is designed and configured by installation to combust only natural gas, hydrogen gas and/or liquefied petroleum gas, or any other gas(es) with a fixed composition vented from specific equipment which has been determined to be equivalent and approved in writing by the Executive Officer.~~

CLEAN SERVICE STREAM is a gas stream such as 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 if determined to be equivalent and approved in writing by the Executive Officer.

~~(2)~~(1)

~~(3)~~(2) EMERGENCY is a condition beyond the reasonable control of the owner or operator of a 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 ~~repetitive~~ flare event ~~from the same equipment~~ caused by poor maintenance, or a condition caused by operator error that results in a flare event shall not be deemed an emergency.

~~(4) EMERGENCY SERVICE FLARE is a flare other than clean service flare that is designed and configured by installation to combust only vent gases as a result of any situation arising from sudden and unforeseeable events beyond the reasonable control of the owner or operator of the gas flare which require immediate corrective action to restore normal and safe operation including emergency process 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.~~

~~(5)~~(3) 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 by an electric generation unit at the 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, or

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

~~(B) Relief valve leakage due to malfunction;~~

~~(C)~~(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 or other gas compliant with Rule 431.1 that is used for the purpose of maintaining the higher heating value of the vent gas above 300 British Thermal Units 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;

~~(D)~~(C) Venting of clean service streams to a clean service flare or a general service flare;

~~(E) Intermittent minor venting from:~~

~~(i) Sight glasses;~~

~~(ii) Compressor bottles;~~

~~(iii) Sampling systems; or~~

~~(iv) Pump or compressor systems; or~~

~~(F) An emergency situation in the process operation resulting from the vessel operating pressure rising above pressure relief devices' set points, or maximum vessel operating temperature set point.~~

(4) 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 means the combustion of vent gases in a flare device. Based on their use, flares are classified as:

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

~~(H)~~(B) GENERAL SERVICE FLARE is a flare that is not a Clean Service Flare.

~~(6)~~(5) FLARE EVENT is any intentional or unintentional combustion of vent gas in a flare. ~~The flare event ends when the flow velocity drops below 0.12 feet per second,~~ 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.

~~(7)~~(6) 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 in a flare.

~~(8)~~(7) FLARE MINIMIZATION PLAN is a document intended to meet the requirements of subdivision (e).

~~(9)~~(8) FLARE MONITORING SYSTEM is the monitoring and recording equipment used for the determination of flare operating parameters, including higher heating value, total sulfur concentration, combustion efficiency, standard volumetric flow rate and/or on/off flow indication.

(9) FLARE TIP VELOCITY is the velocity of flare gases exiting a flare tip averaged over 15 minute~~s~~ time periods, starting at 12 midnight to 12:15 am, 12:15 am to 12:30 am, and so on, concluding at 11:45 pm to midnight, and calculated as the volumetric flow divided by the area of the flare tip.

~~(10) GENERAL SERVICE FLARE is a flare that is not defined in paragraphs (b)(1) or (b)(3) that is designed and configured by installation to combust vent gases as a result of any situation including, but not limited to, relief of excess operating pressures, tank vapor displacement, start-ups, shutdowns, process unit turnarounds and blowdowns, and scheduled and unscheduled maintenance and clean up.~~

~~(11)~~(10) HYDROGEN PRODUCTION PLANT is a facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes, using refinery fuel gas, process gas or natural gas, and which supplies hydrogen for petroleum refinery operations.

~~(12)~~(11) 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.

~~(13)~~(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.

~~(14)~~(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.

~~(15)~~(14) PILOT is an auxiliary burner used to ignite the vent gas routed to a flare.

(15) PLANNED FLARE EVENT is any flaring as a result from process unit(s) or equipment startup, shutdown, turnaround, maintenance, clean-up, and non-emergency flaring. 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.

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

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

~~SAMPLING FLARE EVENT is any flare event for a specific flare exceeding either a flow rate of 330 standard cubic feet per minute continuously for a period greater than 15 minutes, or any other flare event, as requested by the petroleum refinery and approved in writing by the Executive Officer. Sampling flare events that occur within 15 minutes of each other are considered a single event if the facility can demonstrate to the satisfaction of the Executive Officer that the events had a common cause and the release of vent gas originated from the same process unit.~~

(18) 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 replacement of equipment. Stoppage caused by frequent breakdown due to poor maintenance or operator error shall not be deemed a shutdown.

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

~~(19)~~(20) SPECIFIC CAUSE ANALYSIS is a process used by a facility subject to this rule to investigate the cause of a flare event, identify corrective measures and prevent recurrence of a similar event.

~~(20)~~(21) STARTUP is the procedure by which a process unit or piece of equipment achieves normal operational status, as indicated by such parameters as temperature, pressure, feed rate and product quality.

~~(21)~~(22) SULFUR RECOVERY PLANT is a facility that recovers elemental sulfur or sulfur compounds from sour gases and/or sour water generated by petroleum refineries.

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

~~(22)~~(24) VENT GAS is any gas generated at a facility subject to this rule that is routed to a flare, excluding assisting air or steam, which are injected in the flare combustion zone or flare stack via separate lines.

(25) VOLATILE ORGANIC COMPOUNDS (VOC) is as defined in Rule 102.

~~(23)~~(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) Requirements

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

(1) ~~Effective January 1, 2006:~~Maintain a pilot flame present at all times a flare is operational.

(2) 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 (j)(2~~3~~).

(3) Except as specified in (c)(10), operate all general service flares at petroleum refineries such that the flare tip velocity is less than:

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

$$Log_{10}(V_{Max}) = \frac{Net\ Heating\ Value_{Vent\ Gas} + 1{,}212}{850}$$

and the Net Heating $Value_{Vent\ Gas}$ in British Thermal Units per standard cubic foot is determined pursuant to monitoring required in subdivision (g).

(4) Effective January 30, 2019, general service flares at petroleum refineries shall maintain the net heating value of the flare combustion zone gas (NHV_{cz}) at or above 270 British Thermal Units 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 Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

~~(3)~~(5) Conduct an annual acoustical or temperature leak survey of all pressure relief devices connected directly to a flare and repair leaking pressure relief devices no later than the next turnaround. The survey shall be conducted no earlier than 90 days prior to the scheduled process unit turnaround.

~~(4)~~(6) Conduct a Specific Cause Analysis for any flare event, excluding planned shutdown, planned startup and turnarounds, when any of the thresholds in (c)(6)(A) through (C) is exceeded. Flare events resulting from non-standard operating procedure during a planned shutdown, planned startup or turnaround, must also conduct a Specific Cause Analysis when any of the thresholds in (c)(6)(A) through (C) is exceeded.~~when either:~~

(A) Emissions exceed 100 pounds of VOC; or

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

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

(7) Effective January 30, 2019, conduct a Specific Cause Analysis for any flare event at a petroleum refinery when the smokeless capacity of the flare is exceeded and either:

(A) The visible emission limits in paragraph (c)(2) or Rule 401 are exceeded; or

~~(C)~~(B) The flare tip velocity limits in subparagraph (c)(3)(A) 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 ~~to~~ 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) Effective January 30, 2019, no flare event at a petroleum refinery shall occur above the smokeless capacity of the flare under the following conditions:

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

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

(C) Three times at a flare in any consecutive three year period, if the flare events exceed the limits in clauses (c)(10)(D)(i) or (ii), and the 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) If more than one flare exceeds the limits in (c)(10)(D)(i) or (ii) during a single event, and a Specific Cause Analysis demonstrates that the flaring events at these flares have the same root cause, then one flaring event at each flare shall be considered to have exceeded these limits.

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

~~(5)~~(11) Conduct an analysis and determine the relative cause of any other flare events where more than 5,000 standard cubic feet of vent gas are combusted. When it is not feasible to determine relative cause, state the reason why it was not feasible to make the determination.

~~(6)~~(12) ~~Effective September 1, 2006, submit the following information to the Executive Officer:~~ 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.

~~(7)~~(13) ~~Effective January 1, 2007, submit to the Executive Officer an evaluation of options to reduce flaring during planned shutdowns, startups and turnarounds, including, but not limited to slower vessel depressurization, storing vent gases~~Submit to the Executive Officer 12 months after July 7, 2017 ~~*the rule is adopted*~~ 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

~~(i)~~(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:

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

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

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

~~(v)~~

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

~~(vii)~~

~~(viii)~~ 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.

(v)

~~(8)~~(14) ~~Effective January 1, 2007, o~~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. ~~Notwithstanding the effective date above, for the owner or operator of a facility subject to this rule that must install flare gas recovery and treatment system(s) to comply with the requirements of this paragraph, the effective date for a flare directly associated with the proposed flare gas recovery and treatment system shall be January 1, 2009, provided the owner or operator submits a complete application to construct and operate a flare gas recovery and treatment system(s) by July 1, 2006. For a facility installing flare gas treatment and recovery system(s) for more than two flares, the owner or operator may request an extension of the compliance date specified in this paragraph for the flare gas recovery and treatment system serving the additional flares to no later than January 1, 2010. The~~

~~Executive Officer may grant an extension provided that the owner or operator submits a request in writing to the Executive Officer prior to January 1, 2007, and the facility demonstrates that an extension is necessary due to operational needs.~~

~~(9)~~(15) ~~Effective January 1, 2009, p~~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.~~, or relief valve leakage. Notwithstanding the effective date above, for the owner or operator of a facility installing flare gas treatment and recovery system(s) for more than two flares to comply with the requirements of paragraph (c)(4), the owner or operator may request an extension of the compliance date specified in this paragraph for the flare gas recovery and treatment system serving the additional flares to no later than January 1, 2010. The Executive Officer may grant an extension provided that the owner or operator submits a request in writing to the Executive Officer prior to January 1, 2007, and the facility demonstrates that an extension is necessary due to operational needs.~~

(d) Performance Targets

~~(2)~~ The owner or operator of a petroleum refinery subject to this rule shall minimize flare emissions and meet ~~the following~~ a performance target~~s:~~ for

~~(A) Beginning with calendar year 2006, minimize sulfur dioxide emissions from flares to less than 10.35 tons per million barrels of crude processing capacity, calculated as an average over one calendar year;~~

~~(B) Beginning with calendar year 2008, minimize sulfur dioxide emissions from flares to less than 1 ton per million barrels of crude processing capacity, calculated as an average over one calendar year;~~

~~(C) Beginning with calendar year 2010, minimize sulfur dioxide emissions from flares to less than 0.7 tons per million barrels of crude processing capacity, calculated as an average over one calendar year;~~

~~(1) Beginning with calendar year 2012, minimize~~ sulfur dioxide emissions from flares ~~to~~ of less than 0.5 tons per million barrels of crude processing capacity, calculated as an average over one calendar year.

~~(2)~~(1) Compliance with this~~e~~ performance target~~s above~~ shall be determined at the end of each calendar year based on the facility's annual flare sulfur dioxide emissions normalized over the crude oil processing capacity in calendar year 2004.

~~(3)~~(2) In the event the petroleum refinery specific performance target~~s~~ of ~~paragraph~~ subdivision (d)~~(1)~~ is exceeded for any calendar year, the Executive Officer may issue a Notice of Sulfur Dioxide Exceedance that shall become a part of the refinery compliance record.

~~(4)~~(3) In the event the petroleum refinery specific performance target of ~~paragraph~~ subdivision (d)~~(1)~~ is exceeded for any calendar year, the owner or operator of the petroleum refinery shall:

(A) Submit a Flare Minimization Plan pursuant to subdivision (e), and

(B) Pay the District mitigation fees, within 90 days following the end of a calendar year for which the performance target was exceeded, according to the following schedule:

(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.

(iv) ~~Notwithstanding the mitigation fee schedule of this subparagraph, the mitigation fee for a petroleum refinery for a calendar year will not exceed $4,000,000.~~

(e) Flare Minimization Plan

(1) The owner or operator of a petroleum refinery exceeding the performance target~~s~~ in ~~paragraph~~ subdivision (d)~~(1)~~ shall submit, no later than 90 days ~~from~~ after the end of a calendar year with emissions exceeding the annual performance target, a complete Flare Minimization Plan for approval by the

Executive Officer. This plan shall constitute a plan pursuant to Rule 221 and fees shall be assessed pursuant to Rule 306. The plan application shall list all actions to be taken by the petroleum refinery to meet the performance target~~s~~ in subdivision (d), and shall include ~~including~~ 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) Detailed process flow diagrams of all upstream equipment and process units venting to each flare, identifying the type and location of all control equipment;~~

~~(C)~~(B) Refinery policies and procedures to be implemented and any equipment improvements to minimize flaring and flare emissions and comply with the performance target~~s~~ of ~~paragraph~~ subdivision (d)~~(1)~~ for:

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

(ii) Essential operational needs and the technical reason for which the vent gas cannot be prevented from being flared during each specific situation, based on supporting documentation on flare gas recovery systems, excess gas storage and gas treating capacity available for each 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.

~~(D)~~(C) Any flare gas recovery equipment and treatment system(s) to be installed to comply with the performance targets of ~~paragraph~~ subdivision (d)~~(1)~~.

(2) The Executive Officer will make the Flare Minimization Plans available for public review for a period of 60 days and respond to comments received prior to plan approval. The Executive Officer will approve a plan upon determining that it meets the requirements of subdivision (e), or notify the owner or operator in writing that the plan is deficient and specify the

required corrective action. If the owner or operator fails to submit an amendment within 45 days to correct the deficiency, the Executive Officer will deny the Flare Minimization Plan. The facility ~~will~~ 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 ~~from~~ 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) The owner and operator of a petroleum refinery shall comply with all provisions of an approved Flare Minimization Plan. Violation of any of the terms of the plan is a violation of this rule.

(f) Flare Monitoring and Recording Plan Requirements

~~(1)~~ The owner or operator of an existing petroleum refinery, sulfur recovery plant or hydrogen production plant, upon modification or replacement of any monitoring equipment included in an approved Flare Monitoring and Recording Plan shall: ~~as of November 4, 2005, shall:~~

~~(2)~~(1) ~~On or before June 30, 2006,~~ submit a ~~R~~revised Flare Monitoring and Recording Plan, 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)(~~3~~4) of this rule.

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

(A) Comply with the most current Flare Monitoring and Recording Plan approved by the Executive Officer. ~~and in effect prior to November 4, 2005. The Executive Officer will amend the plan to include Rule 1118 as adopted on February 13, 1998, to become part of the plan and will issue the amended plan within 30 days of November 4, 2005.~~ The ~~amended~~ current plan shall remain in effect until ~~the~~ any ~~R~~revised Flare Monitoring and Recording Plan, submitted pursuant to ~~sub~~paragraph (f)(1)~~(A)~~ is 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. Violation of any of the terms of the plan is a violation of this rule.

(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 [Date of amendment] ~~February 13, 1998~~ 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)(~~3~~4) of this rule.

(4) Each Flare Monitoring and Recording Plan ~~or Revised 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 ~~subdivision~~ 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.~~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, ~~and~~ 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 (~~*Date of Amendment*~~July 7, 2017), ~~A~~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.

~~(Q) A request to use the alternative sampling program pursuant to subparagraph (g)(4)(C), if applicable, with a complete description of proposed Quality Assurance/Quality Control procedures to be used in a test program to determine the correlation between the results from the alternative sampling program and the testing and monitoring methods specified in subdivision (j).~~

(g) Operation, Monitoring and Recording Requirements

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

(1) On or before six (6) months after approval of the Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan, start monitoring and recording in accordance with subdivision (g) and the

provisions in the approved Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan.

(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) Perform monitoring and recording of the operating parameters, as applicable, according to the monitoring and recording requirements and frequency shown in Table 1 (including footnotes) below, except as specified in paragraph (g)(4) and (g)(5).

~~TABLE 1~~

~~Effective until June 30, 2007~~

~~TYPE OF FLARE~~	~~OPERATING PARAMETER~~	~~MONITORING AND RECORDING~~
~~Clean Service~~	~~Vent Gas Flow~~[1]	~~Measured and Recorded~~[2] ~~Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)~~
	~~Vent Gas Higher Heating Value~~ [3]	~~Calculated~~[5]
	~~Vent Gas Total Sulfur Concentration~~[4]	~~Calculated~~[5]
~~General Service~~	~~Vent Gas Flow~~[1]	~~Measured and Recorded~~[2] ~~Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)~~
	~~Vent Gas Higher Heating Value~~ [3]	~~Continuously Measured and Recorded with a Higher Heating Value Analyzer~~
	~~Vent Gas Total Sulfur Concentration~~[4]	~~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. Higher (Gross) Heating Value in British Thermal Units per Standard Cubic Foot.~~

~~4. Total Sulfur as SO_2, ppm.5.Based on the default emission factors in attachment B1 or alternative emission factors as approved by the Executive Officer as part of a Flare Monitoring and Recording Plan~~

TABLE 1

~~**Effective July 1, 2007**~~

TYPE OF FLARE	OPERATING PARAMETER	MONITORING AND RECORDING
Clean Service	Gas Flow[1]	Measured and Recorded[2] Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)
	Gas Higher Heating Value [3]	Calculated or Continuously Measured and Recorded with a Higher Heating Value Analyzer ~~Representative Sample for Each Flare Event~~
	Total Sulfur Concentration[4]	Calculated or Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer~~Representative Sample for Each Flare Event~~
~~Emergency Service~~	~~Gas Flow[1]~~	~~Measured and Recorded[2] Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)~~
	~~Gas Higher Heating Value [3]~~	~~Continuously Measured and Recorded with a Higher Heating Value Analyzer~~
	~~Total Sulfur Concentration[4]~~	~~Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer~~
General Service	Gas Flow[1]	Measured and Recorded[2] Continuously with Flow Meter(s) with or without on/off flow indicator(s)
	Gas Higher Heating Value [3]	Continuously Measured and Recorded with a Higher Heating Value Analyzer

	Total Sulfur Concentration[4]	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. Higher (Gross) Heating Value in British Thermal Units per Standard Cubic Foot.
4. Total Sulfur as SO_2, ppmv.

(4) Alternative Flare Vent Gas Sampling

(A) In cases where sampling of vent gas is exempted pursuant to paragraph (k)(1), the owner or operator of a gas flare shall identify for each 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 (e.g. total sulfur concentration) which is necessary to calculate flare emissions using the guidelines in Appendix B for substituted data. The estimated emissions, subject to approval by the Executive Officer as representative of emissions from that flare event, shall be reported and submitted with the quarterly report as specified in paragraph (i)(4).

~~(B) The owner or operator of a flare may comply with the vent gas sampling requirements of paragraph (g)(3) based on alternative criteria for determining a sampling flare event for each specific flare, provided that such alternative criteria are submitted as part of the Flare Monitoring and Recording Plan in subparagraph (f)(3)(P), and are approved in writing by the Executive Officer.~~

~~(C) During the interim period, which is after the approval of the Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan and until in compliance with paragraph (g)(1), an alternative sampling program for sampling flare events for each flare may be used provided the following requirements are met:~~

~~(i) A request to use an alternative sampling program has been submitted by the flare owner or operator as part of the Flare Monitoring and Recording Plan pursuant to subparagraph~~

~~(f)(3)(Q) and approved as equivalent by the Executive Officer. The Executive Officer must make a finding, in the case of an existing facility, that compliance with subparagraph (f)(1)(B) is not feasible.~~

~~(ii) The vent gas(es) to each flare shall be sampled and analyzed, if applicable, for total sulfur and higher (gross) heating value in accordance with methods specified in subdivision (j), once a day. If there is a sampling flare event in any day, the sampling and analysis shall also be conducted during such event in addition to the daily sampling requirement.~~

~~(iii) In addition to the samples collected and analyzed pursuant to the requirements in clause (g)(4)(C)(ii), the vent gas(es) to each flare shall be sampled and analyzed in accordance with Table 1, as follows:~~

~~(I) Once a day during each sampling flare event other than the flare event specified in clause (g)(4)(C)(ii), if such a sampling event occurs during that day.~~

~~(II) For all sampling flare events that are the result of any process unit shutdown.~~

~~(iv) The vent gas(es) to each flare shall be sampled and analyzed for all other sampling flare events to measure hydrogen sulfide concentrations in the vent gas using a colorimetric method or other methods as specified in the Flare Monitoring and Recording Plan pursuant to subparagraph (f)(3)(Q) and as approved in writing by the Executive Officer.~~

~~(D) After the interim period of monitoring and recording pursuant to subparagraph (g)(4)(C), the owner or operator of a flare may, based on the monitoring data, request a change in the vent gas sampling requirement of paragraph (g)(3) and/or propose an equivalent alternative criteria for determining a sampling flare event for each specific flare, provided that the owner or operator of the flare submits an application for the modification to the Flare Monitoring and Recording Plan and can demonstrate, and obtain written approval of the Executive Officer that an alternative vent gas sampling and/or an alternative criteria for determining a sampling~~

~~flare event for each specific flare is equivalent to the sampling requirement of paragraph (g)(3) and is adequate to determine the quality of vent gas(es) and to calculate emissions from all such flare events.~~

~~(E) After the interim period of monitoring and recording pursuant to subparagraph(g)(4)(C), the Executive Officer may revise any alternative criteria for determining a sampling flare event for each specific flare or any alternative vent gas sampling which have been previously proposed by the owner or operator of a flare and approved by the Executive Officer, if the Executive Officer determines that the alternative(s) is not adequate based on the monitoring data or other information to determine the quality of vent gas(es) and to calculate emissions from all such flare events. The owner or operator of the flare shall use the revised criteria for determining a sampling flare event or vent gas sampling to monitor and record flare events no later than 30 days after written notification by the Executive Officer.~~

(5) Flare Monitoring System

(A) Maintain any flare monitoring system, used to ensure compliance with paragraph (g)(3) of this rule, in good operating condition at all times when the flare that it serves is operational, except when out of service due to:

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

(ii) Planned maintenance, which shall not exceed 14 days per 18 month period commencing the start of 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) A flare monitoring system may be used to measure and record the operating parameters required in paragraph (g)(3) of this rule for more than one flare provided that:

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

(ii) ~~Effective July 1, 2007, i~~If the flare monitoring system is used to measure and record the operating parameters for ~~emergency service flares, as well as~~ general service flares, the flare monitoring system shall consist of a continuous vent gas flow meter, a continuous higher heating value analyzer, a total sulfur analyzer and recorder that meet the requirements specified in Attachment A.

(6) Monitor the presence of a pilot flame using a thermocouple or any other equivalent device approved by the Executive Officer to detect the presence of a flame.

~~(7) Effective July 1, 2006, m~~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, monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare, the flame of flares that are not enclosed, and a sufficient area above the flame of all flares that is suitable for visible emissions observations, at a rate of no less than one frame every 15 seconds.

(7)

~~(8) Effective January 1, 2007, for all emergency and~~ All general service flares~~:~~

(8) ~~Install each~~ shall:

(A) Have a flow meter installed in a manner and at a location that would allow for accurate measurements of the total volume of vent gas to each flare. If the flow meter cannot be placed in the location that would allow for accurate measurement due to physical constraints, the operator shall retrofit or equip the existing flow meters with totalizing capability to indicate the true net volume of gas flow to each flare.

~~(B) Install an automated sample collection system at each flare, capable to alert personnel that a sample is being collected following the start of a sampling flare event, unless total sulfur is monitored with a certified analyzer approved by the Executive Officer.~~

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

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

(A) Install, operate, calibrate, maintain, and record data from any monitoring systems required by Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries that are not already required by paragraph (g).

(h) Recordkeeping Requirements

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

~~(1) For a period of 90 days for the information required under paragraph (g)(7); and~~

~~(2) For a period of five (5) years for all the information required under paragraphs (g)(3), (g)(4), (g)(5), (g)(6) and (g)(7), as applicable.~~

(i) Notification and Reporting Requirements

~~Effective January 1, 2006, t~~The owner or operator of a flare shall:

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

(2) Notify the Executive Officer ~~by telephone~~ via the Web-Based Flare Event Notification System within one hour from the start of any unplanned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or exceeding 500,000 standard cubic feet of flared vent gas.~~, and~~

~~(3) Submit a Specific Cause Analysis as required by subparagraph (c)(1)(D) to the Executive Officer within 30 days, identifying the cause and duration of the unplanned flare event, and any mitigation and corrective actions taken. The owner or operator may request the Executive Officer to grant an extension of up to 30 days to submit the Specific Cause Analysis.~~

(3) Notify the Executive Officer via the Web-Based Flare Event Notification System at least 24 hours prior to the start of a 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**.** Within one hour of the start of a planned flare event, submit a notification via the ~~w~~Web-~~b~~Based ~~Refinery~~ Flare Event Notification System, referencing the notification number assigned to the planned flare event at the time of the original ~~telephone~~ notification.

(4) Notify the Executive Officer via the Web-Based Flare Event Notification System within one hour after the cumulative daily total amount of flare gas vented from a flare exceeds 100,000 standard cubic feet, if a notification has not already been provided for that day pursuant to paragraphs (i)(2) or (i)(3).

~~(4)~~(5) If the Web-Based Flare Event Notification System is not available, or if functions within the Web-Based Flare Event Notification System do not allow facilities to enter the necessary information required in (i)(2) through (i)(4), then notifications shall be made to 800-CUT-SMOG (800-288-7664).

~~(5)~~(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 ~~sub~~paragraphs (c)(~~1~~6),~~(D) and~~ (c)(7), and (c)(~~1~~11)~~(E)~~ 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 ~~sub~~paragraph (c)(~~1~~5)~~(C)~~. 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 D~~-2382-88~~4809-13, ASTM Method D ~~3588-91~~ 3588-98(2011),~~or~~ ASTM Method D~~-4891-89~~4891-13, or other ASTM standard as approved by the Executive Officer, and

(ii) ~~Effective July 1, 2007, w~~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 ~~5504-01~~5504-12, or other ASTM standard as approved by the Executive Officer, and

(ii) ~~Effective July 1, 2007, w~~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) Until the continuous and semi-continuous analyzers are certified by the Executive Officer and operational, analyses for higher (gross) heating value and total sulfur concentration shall be:~~

~~(A) Conducted by a District approved lab; or~~

~~(B) Conducted by the owner or operator of a gas flare if the District has provided prior written approval of QA/QC and standard operating procedures. All analytical reports shall be signed by the facility official responsible for analytical equipment to certify the accuracy of the reports.~~

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

(3) Notwithstanding ~~sub~~paragraph~~s~~ (j)(1)~~ and (j)(2)~~, 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) Exemption

(1) Notwithstanding a flare monitoring system, consisting of a flow meter, higher heating value analyzer, net heating value analyzer and total sulfur analyzer that is in operation, sampling and analyses of representative samples for higher heating values, net heating values, and total sulfur concentration pursuant to paragraph (g)(3) may not be required for any flare event that:

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

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

(2) Any sulfur dioxide emissions, visible emissions prohibited in paragraph (c)(10), and flare tip velocities that exceed limits in subparagraph (c)(3)(A) from flare~~ing~~ events caused by external power curtailment beyond the operator's control~~,~~ (excluding interruptible service agreements), natural disasters or acts of war or terrorism shall not count towards either:

(A) ~~t~~The performance targets specified in subdivision (d) upon submittal of documentation proving the existence of such events and certified in writing by the petroleum refinery official responsible for emission reporting; or

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

ATTACHMENT A

FLARE MONITORING SYSTEM REQUIREMENTS

The components of each 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 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 shall be corrosion resistant. If required by the petroleum refinery or the hydrogen production plant, 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:	$\underline{+}$ 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 District Rule 218.1. 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 during a 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 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 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. See rule 218.1 (a)(23) 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.

q. Periodically perform a zero drift test. Allowed zero drift should be consistent with a properly operating system. See rule 218.1 (a)(32) 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 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. See rule 218.1(a)(23) 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.

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) 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 F

ATTACHMENT B

GUIDELINES FOR CALCULATING FLARE EMISSIONS

The following methods shall be used to calculate flare emissions. An alternative method may be used, utilizing 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 operators shall use the following equations and emission factors to calculate emissions from vent gas, natural gas, propane and butane:

Effective No Later Than January 30, 2019, or As Soon As Monitors Are Installed and Certified That Can Measure Net Heating Value

Vent Gas

Air Pollutant	Equation	Emission Factor
ROG	E = V x ~~H~~NHV x EF	~~0.063~~ 0.66 lb/mmBTU
NOx[1]	E = V x HHV x EF	0.068 lb/mmBTU
CO	E = V x ~~H~~NHV x EF	~~0.37~~0.31 lb/mmBTU
PM10	E = V x EF	21 lb/mmSCF
SOx	E = V x Cs x 0.1662	Note (~~1~~2)

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
NOx[1]	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 (~~1~~2)

Where:

E = Calculated vent gas emissions (lbs)

V= Volume flow of vent gas, as measured in million standard cubic ~~foot~~ feet at 14.7 psia and 68^0 Fahrenheit

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

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

EF = Emission Factor

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

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

Note (~~1~~2) If an approved total sulfur analyzer is used in accordance with this rule, Cs is the concentration of total sulfur in the vent gas, averaged over 15 minutes or less, if the event duration is shorter than 15 minutes.

~~Note (2) For a flare event where a representative sample or other sampling method is not required pursuant to Table 1 of this rule, use HHV and/or Cs from any representative sample of a flare event on the same day. If no representative sample is taken that day, use HHV and/or Cs from the last representative sample taken prior to the flare event.~~

Natural Gas

Air Pollutant	Equation	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

Propane and Butane

Air Pollutant	Equation	Emission Factor (lb/mmBTU)
ROG	E = V x 3500 x EF	~~0.003~~0.009
NOx	E = V x 3500 x EF	~~0.13~~0.145
CO	E = V x 3500 x EF	~~0.032~~0.082
PM10	E = V x 3500 x EF	~~0.0014~~0.002
SOx(1)	E = V x 3500 x EF	0.047

Note (1) If the concentration of total sulfur in the vent gas or in the process streams vented to the flare is measured, the operator shall use E = V x Cs x 0.1662 to estimate the SOx emissions.

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 for the flow rate for each 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 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), 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 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. Data Substitution Procedures

For any time period for which the 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 demonstrates using verifiable records of flare water seal level and/or other parameters as approved by the Executive Officer in the Flare Monitoring and Recording Plan or the Revised Flare Monitoring and Recording Plan that no 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, the totalized flow shall be calculated from the methodology in section 2(a)(i) below, unless the Executive Officer approves the method specified in Section 2(a)(ii).

i) The totalized flow shall be calculated from the product of the 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:

$$FR = Max.\ FR - 0.5(Max.\ FR - Avg.\ FR)$$

Where:

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

Max FR = Maximum flow rate that was measured and recorded for that flare during the previous 20 quarters preceding the flare event. This maximum value is based on the average flow rate during an individual flare event, not an instantaneous maximum value.

Avg FR = Average flow rate for all measured and recorded flow rates for all sampled flare events for that flare, during the previous 20 quarters preceding the subject flare event.

The duration of a 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 or Revised Flare Monitoring and Recording Plan.

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

ii) 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, 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 pursuant to the requirements of this rule, the higher heating value shall be calculated from the methodology in section 2(b)(i) below, unless the Executive Officer approves the method specified in Section 2(b)(ii).

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

$$HHV = Max\ HHV - 0.5(Max\ HHV - Avg\ HHV)$$

Where:

HHV = Estimated higher heating value (Btu/scf)

Max HHV = Maximum HHV measured and recorded for that flare during the previous 20 quarters preceding the flare event.

Avg HHV = Average value of all HHV measured and recorded for that flare for all sampled flare events during the previous 20 quarters preceding the flare event.

ii) 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, 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 pursuant to the requirements of this rule, it shall be calculated from the methodology in section 2(c)(i) below, unless the Executive Officer approves the method specified in Section 2(c)(ii).

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:

$$SFE = Max\ SFE - 0.5(Max\ SFE - Avg\ SFE)$$

Where:

SFE	=	Estimated total sulfur concentration, expressed as sulfur dioxide (ppmv)
Max SFE	=	Maximum total sulfur concentration expressed as sulfur dioxide measured and recorded for that flare during the previous 20 quarters preceding the flare event.
Avg SFE	=	Average value of all total sulfur concentrations measured and recorded for that flare for all sampled flare events during the previous 20 quarters preceding the flare event.

ii) 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 expressed as sulfur dioxide, may be used to determine the total sulfur concentration in lieu of the method specified above.

ATTACHMENT G

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Staff Report

Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

July 2017

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EXECUTIVE SUMMARY

In recent years, incidents at refineries, including offsite power disruptions and onsite process unit breakdowns, resulted in flaring events and increased emissions. These recent significant flaring events at refineries have resulted in increased public concern over the potential air quality impact of flaring emissions. Flaring activities have been conducted as a safety measure to relieve pressure in process units that are temporarily not operating within design parameters. Flaring also commonly occurs through routine activities such as planned start-ups/shut-downs of process units and facility turnarounds.

In 2012 U.S. EPA initiated a review of its Refinery Regulations, New Source Performance Standards (NSPS), and 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, including flare operations. The review resulted in a Final Refinery Sector Rule released in December 2015. These updated federal requirements for flaring focus on reducing significant flaring events, and ensuring that when flaring does occur, combustion is as efficient as possible in order to reduce emissions. Based on recent studies, in December 2016, EPA also revised its AP-42 guidance for estimating Volatile Organic Compounds (VOC) emissions from flaring, increasing the emission factor about 10-fold.

Staff is proposing to amend Rule 1118 in two phases. Proposed amendments presented in this staff report represent the first phase, while the second phase of rulemaking is expected to begin in 2018 and result in a proposal for Board consideration in 2020. In this first phase for Proposed Amended Rule 1118, staff is recommending to:

1. Harmonize Rule 1118 with key updates from U.S. EPA's recent Refinery Sector Rule update regarding flares, including new prohibitions on some types of flaring,
2. Require facilities subject to Rule 1118 to prepare a Scoping Document that evaluates the feasibility of minimizing or avoiding planned and unplanned flaring events,
3. Remove the $4 million annual cap on mitigation fees that facilities may pay for flaring,
4. Update emission factors based on EPA's updated AP-42 guidance, and
5. Update and clarify reporting requirements for facilities.

In the second phase of rulemaking, staff is proposing to use the information from Scoping Documents provided by facilities, the updated reporting requirements, and potentially the results from a separate Optical Remote Sensing Pilot Study that staff is proposing to develop a more comprehensive update to Rule 1118, though concepts for this second phase ~~that~~ have not yet been developed.

BACKGROUND

Introduction

In recent years several incidents at some refineries, including offsite power disruptions and onsite process unit breakdowns, resulted in flaring events and increased emissions, impacting neighboring communities. The amount of flaring that has occurred in recent years has varied, with some refineries flaring more than others (described further below). Whether from unplanned events like external power disruptions or onsite emergencies, or from planned events like refinery turnarounds, flaring occurs when the Flare Gas Recovery (FGR) system is unable to handle the amount or type of gases being directed into that system at that time. Vent gases generated during the refining process (typically hydrocarbons) are often sent to the FGR system, where they are recovered by injecting them into the refinery's fuel gas system for use in other processes, such as fuel for a steam boiler. However, if the amount of gas coming into the FGR system is higher than the capacity of that system, for example higher than the gas compressor capacity of the FGR system, then the extra gas is discharged into the atmosphere at the flare tip to avoid unsafe over-pressurization. These gases are then combusted at the flare tip to reduce emissions and the potential buildup of combustible gases. While this simplified explanation describes why flaring occurs, individual flaring events ~~all~~ have their own unique cause and each refinery has varying abilities to prevent and/or handle flaring due to the complexity of each refinery.

All refineries in the SCAQMD have FGR systems, partially as a result of Rule 1118, and the amount of flaring has been reduced since the last amendment to the rule in 2005. However, some refineries continue to experience thousands of individual 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 (PAR) 1118 seeks to build upon the improvements that refineries have made, and reduce flaring even further. This rulemaking effort consists of a phased approach, where Phase I includes mechanisms to gather more information, and adjusts the rule to be consistent with federal requirements (described below). Phase II of the rulemaking will begin in 2018 and will act upon the information gathered from Phase I, and will seek more comprehensive changes to the rule.

The amendments being sought or considered in Phase I include:

1. Harmonize Rule 1118 with key updates from U.S. EPA's recent Refinery Sector Rule update regarding flares, including new prohibitions on some types of flaring,
2. Require facilities subject to Rule 1118 to prepare a Scoping Document that evaluates the feasibility of minimizing or avoiding planned and unplanned flaring events,
3. Remove the $4 million annual cap on mitigation fees that facilities may pay for flaring,
4. Update emission factors based on EPA's updated AP-42 guidance, and
5. Update and clarify reporting requirements for facilities.

Each of these proposed amendments is described in more detail below. In addition to these rule amendments, staff is proposing to initiate an optical remote sensing Pilot Study to evaluate the viability of emerging technologies' ability to monitor emissions above the flare tip. ~~That will be handled through a separate Board item at a future date.~~That is being brought to the Board as a separate item at the same meeting.

Flaring Emissions

The types of refinery operations subject to this rule are petroleum refineries, sulfur recovery plants that recover sulfur compounds from sour water generated by petroleum refineries and hydrogen production plants that produce hydrogen from refinery gas and supply hydrogen for petroleum refinery operations. The gas flares are used for the combustion and disposal of combustible gases due to emergency relief, overpressure, and process upsets, startups, shutdowns and other operational and safety reasons. Presently, there are eight operating petroleum refineries, one sulfur recovery plant and three hydrogen production plants with a total of 31 existing flares affected by this proposed amended rule.

Facilities Subject to Rule 1118

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

Under the existing Rule 1118, facilities ~~subject to the rule~~ must report their flaring emissions by category every quarter to SCAQMD. Rule 1118 requires facilities to classify all flaring events using one of the categories listed ~~in the box~~ below.

Categories of Flaring

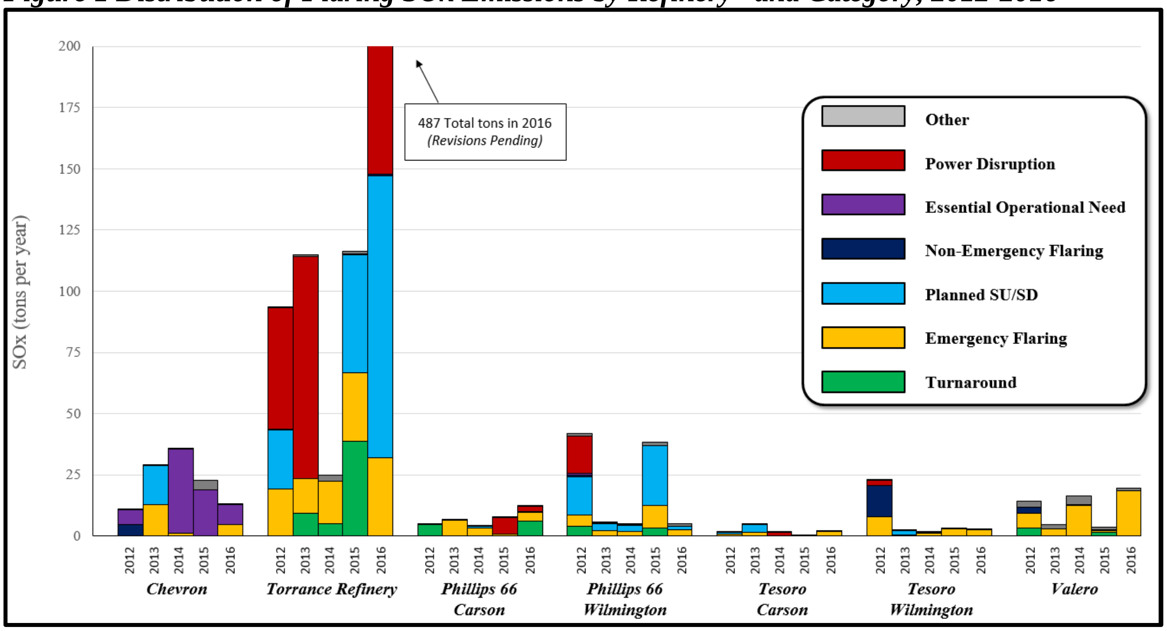
Turnarounds	Essential Operational Need (EON) – Clean Service Stream
Planned Maintenance	EON – Intermittent Minor Venting
Planned Start-up / Shut-down (SU/SD)	EON – Pressure/Temperature Excursion
Emergency Flaring	EON – Relief Valve Leakage
Non-Emergency Flaring	EON – Temporary Fuel Gas Imbalance
Minor Venting (<5,000 standard cubic feet)	EON – Unrecoverable Stream
Undetermined / Other	
Force Majeure (power disruption, Natural disaster, acts of war/terrorism)	

In addition to the category of flaring, each facility must report the following information for each flaring event: criteria pollutant emissions (including sulfur oxides [SOx], volatile organic compounds [VOC], particulate matter [PM], carbon monoxide [CO]), the start and end time of the event, the heating value of the vent gas, the total vent gas flow, and which flare was used.

SOx Emissions

Although there have been nearly 59,000 reported flaring events between 2012-2016, about 44% of the total SOx emissions (506 tons of SOx out of a total of 1,158 tons) have been reported from 13 power disruption events. All other remaining events have resulted in 652 tons of emitted SOx. Of these ~59,000 non-power disruption events, approximately 96% of the total SOx emitted from flaring has come from the top 1% of flaring events. Further, 62% of all SOx has come from the top 50 non-power disruption flaring events. This distribution of emissions data indicates that while flaring is a common occurrence, the bulk of flaring emissions come from just a small number of high emitting events. Figure 1 provides a more detailed distribution of SOx emissions caused by flaring at each facility since 2012.

Figure 1 Distribution of Flaring SOx Emissions by Refinery* and Category, 2012-2016

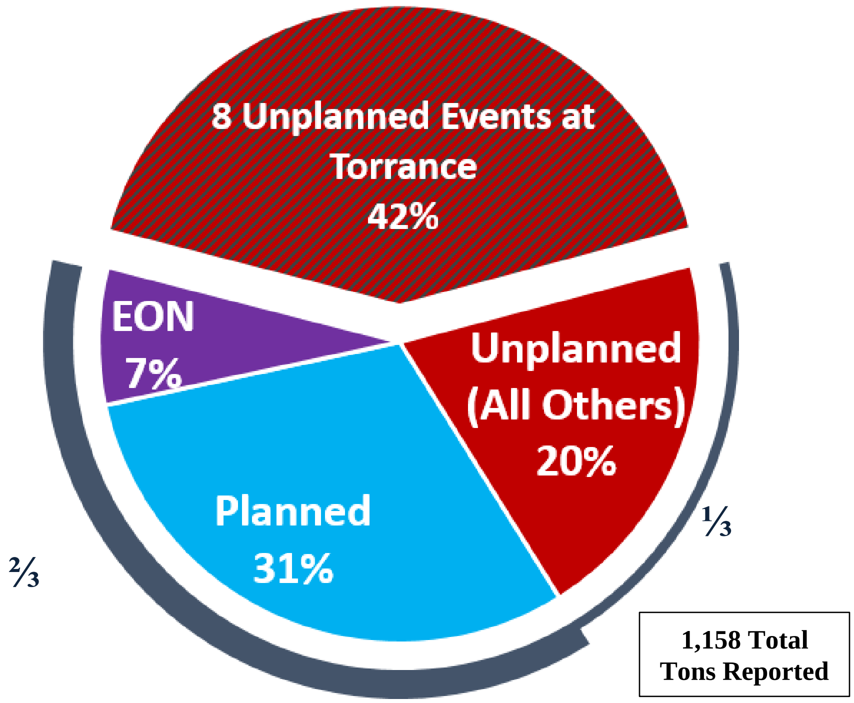


**Five other facilities subject to Rule 1118 emitted <1.0 tons of SOx cumulatively between 2012-2016.*

As illustrated in this chart, flaring emissions are not uniform, with emissions varying by year, category, and facility. Outside of emissions from external power disruptions, the largest source of flaring is from planned events, such as planned start-ups/shutdowns, and turnarounds. The pie chart in Figure 2 ~~below~~ illustrates the cumulative total SOx emissions from flaring, using simplified categories. As seen in Figure 2, a significant portion of the emissions is reported from eight individual power disruption events at the Torrance Refinery.[1] Outside of these eight events, planned flaring events and essential operational needs (e.g., from flaring of gases that are incompatible with the fuel gas system) make up two-thirds of the remaining emissions.

[1] Torrance Refinery submitted a draft revised estimate of their 2016 reported emissions which would reduce the estimated emissions if approved by SCAQMD.

Figure 2 Total SOx Flaring Emissions from 2012-2016 from All Rule 1118 Facilities



Torrance Refinery Flaring

Significant flaring that has occurred at the Torrance Refinery (previously ExxonMobil) recently from power disruptions was recently addressed in February 2017 through a Stipulated Order for Abatement with the SCAQMD Hearing Board.[2] This order, agreed to by Torrance Refinery, requires the facility to:

- Provide information regarding its plan to upgrade its power connection with the local electrical utility to a direct 220 kV connection, and conduct public outreach regarding the plan;
- Evaluate a temporary supply of steam to its flares that would be available during power outages;
- Evaluate the critical onsite utility systems (e.g., steam, nitrogen) that may need upgrading in case of power outages, and install all feasible upgrades within one year after receiving a permit or during the next facility turnaround;
- Evaluate all safety critical devices to determine which do not have backup power supply, and install backup within one year of receiving a permit or during the next facility turnaround; and
- Conduct refresher training on refinery procedures during a power outage.

[2] Available here: http://www.aqmd.gov/docs/default-source/compliance/Torrance-Refinery/stipulated-order-for-abatement-torrance-refinery-215-216-2017.pdf

SOx Mitigation Fund

Under Rule 1118, facilities must pay a Mitigation Fee if their SOx emissions exceed a Performance Target. The current version of Rule 1118 set a progressively declining Performance Target that began at 1.5 tons per million barrels of crude processing capacity[3] (tons/MMbbl) in 2006, and was reduced to its current level of 0.5 tons/MMbbl by 2012. All flaring emissions with the exception of those occurring from Force Majeure events (such as power disruptions) are subject to this fee. The fee level is set at:

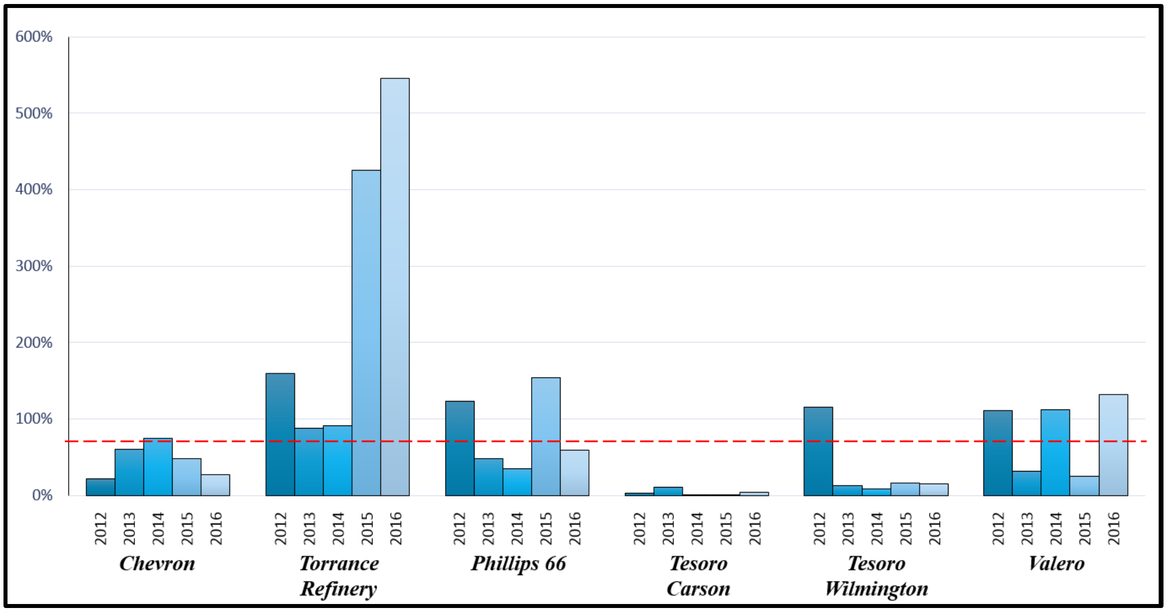
- $25,000 per ton up to 10% over the Performance Target
- $50,000 per ton between 10% and 20% over the Performance Target
- $100,000 per ton when 20%+ of the Performance Target
- With an annual cap of $4,000,000 per year

The chart in Figure 3 below illustrates each facility's SOx emissions relative to its performance cap between 2012-2016. To date, approximately $22.5 million has been deposited into a Mitigation Fund held by SCAQMD, with about 85% of this amount collected over the past three years, and more than three quarters collected from Torrance Refinery (or its predecessor).[4] This mitigation fund can only be spent with authorization from the SCAQMD Governing Board. A program for spending these mitigation fees will be developed outside of this rulemaking process.

The lowering of the performance targets from 2006 to 2012 has led to an increased number of exceedances of the Performance Targets in recent years. Four facilities have exceeded their targets a total of 8 times since 2012, as shown in the chart below. Note that target exceedances in 2016 for two facilities are not yet final as estimates are still being reviewed by SCAQMD staff. The most significant exceedances have been reported by the Torrance Refinery. The 2012 exceedance was due to the identification of a bypass around the flare vent gas flowmeter in 2013 that meant the facility had been under-reporting their emissions, and was required to nearly double their reported emissions for 2012. This problem was corrected in 2013. The Torrance Refinery's second exceedance occurred in 2015, when an explosion in the Electrostatic Precipitator~~Precipitator~~ (ESP) unit caused a shutdown (for the next ~12 months) of the Fluid Catalytic Cracking (FCC) unit. The remainder of the refinery was able to operate only at a low capacity for the remainder of the year, and multiple units were shut down for maintenance throughout that year. These two periods of flaring by Torrance Refinery are the only times that a facility has reached the annual cap of $4,000,000.

[3] Based on calendar year 2004 crude processing capacity.
[4] Hereinafter, the Torrance Refinery will refer to itself and its predecessor Exxon Mobil.

Figure 3 Flaring SOx Emissions as a Percentage of Annual Performance Target

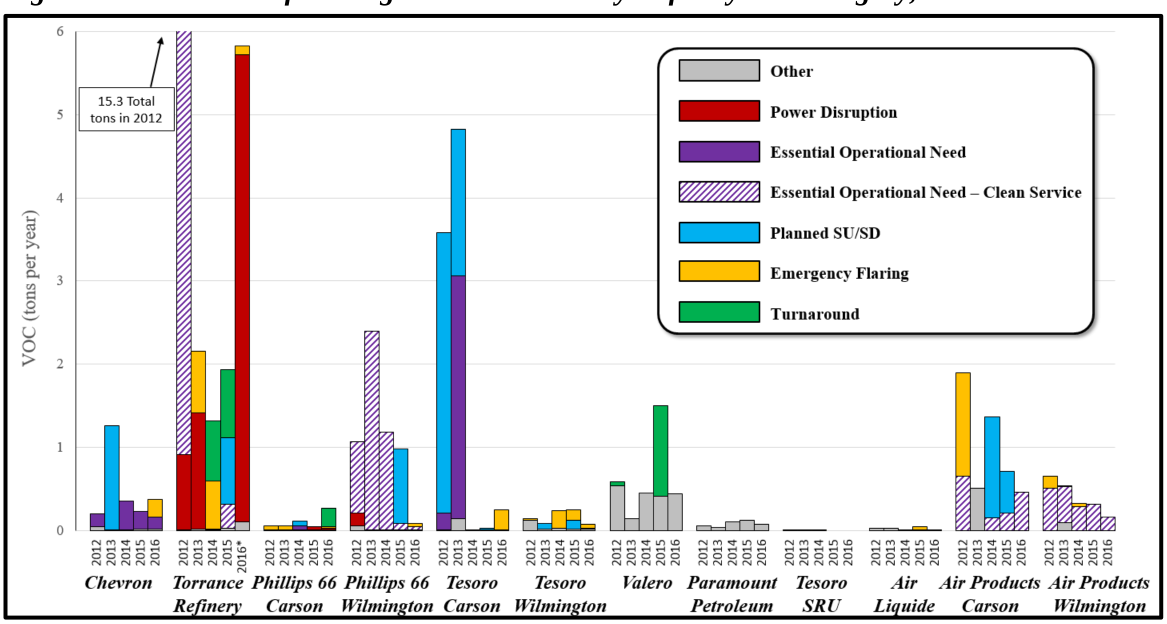


*Torrance Refinery has submitted a revision request for 2016 emissions.

VOC Emissions

Although SOx emissions are used as the basis for paying mitigation fees under Rule 1118, there are other pollutants that are also emitted, including VOCs. While fees are not paid into the Rule 1118 Mitigation Fund for VOC emissions, facilities must pay annual emissions fees under Rule 301 for all flaring emissions, including those occurring under a Force Majeure event. Because some flaring of vent gases contain low levels of sulfur dioxide (such as clean service streams like natural gas or butane), the distribution of emissions among facilities shown below is different than that for SOx.

Figure 4 Distribution of Flaring VOC Emissions by Refinery and Category, 2012-2016



*Torrance Refinery has submitted a revision request for 2016 emissions

As seen in the chart above, some of the facilities subject to Rule 1118 that are not large refineries also emit VOCs at a similar level as some large refineries, largely due to their flaring of clean service streams, either as an Essential Operational Need, or through other flaring events.

Flaring Destruction Efficiency

A key factor in determining the amount of VOCs emitted during flaring events is the destruction efficiency of combustion. The vent gases being released at the flare tip may be composed partially or entirely of VOCs. If the VOCs in the vent gas is entirely combusted with 100% efficiency at the flare tip (i.e. 100% combustion efficiency), then the only byproducts would be carbon dioxide and water (vapor). Similarly, the destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound (such as carbon dioxide, carbon monoxide, or other hydrocarbon intermediate). The destruction efficiency is higher than the combustion efficiency, though it is generally estimated that a combustion efficiency of 96.5% is equivalent to a destruction efficiency of 98%.

Estimated VOC Emissions from Flaring

EPA recently conducted a review of flaring[5] emissions and found that several factors could affect destruction efficiency, such as the amount of steam or air injected into the flare combustion zone (i.e. steam or air assist), the heating value of the flare gas, and the rate of flare gas discharge. Each of these factors ultimately affect the net heating value of the gases in the combustion zone (measured in millions of British Thermal Units [MMBTU]). If the net heating value of the combustion zone gases is too low, then the destruction efficiency is reduced and a larger amount of VOCs is released into the atmosphere.

As part of this review of flaring emissions, EPA updated its AP-42 emissions guidance for VOC. The current VOC emission factor in Rule 1118 is based on the AP-42 Total Hydrocarbon (THC) emission factor of 0.14 pounds per MMBTU, with an assumption that 55% of the THC is methane[6], yielding a final emission factor of 0.063 pounds VOC per MMBTU. Based on a review of more recent studies, the updated AP-42 guidance provides an updated VOC emission factor and states that "[t]he THC emissions factor may not be appropriate for reporting VOC emissions when a VOC emissions factor exists". The updated AP-42 emission factor applies to "well-operated flares achieving at least 98% destruction efficiency" and is now 0.66 pounds VOC per MMBTU.

During the rulemaking process, comments were made regarding the accuracy of the propane and butane combustion emission factors listed in Attachment B of PAR 1118 and whether these emission factors were part of EPA's review. The emission factors in the existing rule were derived from EPA's AP-42 Section 1.5 – Liquefied Petroleum Gas Combustion. During the last amendment to Rule 1118 in 2005, the latest version of this AP-42 chapter available was from April 1993. As this AP-42 chapter was updated in 2008, the emission factors in Attachment B

[5] Table 13.5-2 in EPA AP-42 (2016) Chapter 13.5 https://www3.epa.gov/ttn/chief/ap42/ch13/final/C13S05_12-13-16.pdf.

[6] See page 13.5-5 in EPA AP-42 (1995) Chapter 13.5 https://www3.epa.gov/ttn/chief/ap42/oldeditions/5th_edition/ap42_5thed_orig.pdf.

[6] See page 1.5.1 in https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s05.pdf.

have been updated in PAR 1118 for propane and butane combustion to be consistent with EPA's most recent guidance. Clarifying text was added to Attachment B after the Set Hearing version of PAR 1118 was released that indicates that facilities can use alternative calculation methods only if those methods are supported by facility-specific data, such as monitoring and/or gas composition data. This will require any facility that has emission factors in their currently approved Flare Monitoring and Recording Plan (FMRP) that are different than those approved in PAR 1118 to utilize the updated emission factors immediately, unless the factors in the approved FMRP were based on facility-specific data.

SCOPING DOCUMENT TO EVALUATE POTENTIAL ELIMINATION OF PLANNED FLARING

As shown in Figure 1 ~~above~~, emissions from Planned Events and Essential Operational Needs make up about two thirds of total SOx flaring emissions, outside of eight large flaring events reported from Torrance Refinery. Of this two thirds, the majority is from Planned Flaring Events such as start-ups, shut-downs, and turnarounds. There are many potential ways to reduce flaring from Planned Events, such as:

- Increasing the capacity of the Flare Gas Recovery and Treatment System.
- Ensuring that when excess flare gases are produced that could be diverted into the refinery fuel gas system, that there are consumers of this fuel at the time (e.g., boilers, heaters, cogeneration units).
- Taking longer periods of time to start-up and shut-down process units, for example through slower vessel depressurization.
- Reviewing and revising refinery processes/procedures before Planned Events occur to reduce flaring.

Because facility operators know their processes best, staff is proposing to require facility operators to conduct an evaluation of two alternatives to eliminate Planned Flaring Events. In addition to evaluating the elimination of Planned Flaring, facility operators must also present an analysis of how to reduce emissions from Planned Flaring Events to much lower levels than is currently required by the rule, such as 0.1 and 0.05 tons of SOx per million barrels of crude processing capacity (tons/MMbbl). Table 1 below shows the distribution of the number of times that facilities have met or surpassed targets of 0.25, 0.1, and 0.05 tons/MMbbl between 2012 and 2016, based on reported emissions. Per Rule 1118, if the facility exceeds 0.5 tons/MMbbl, they must pay Mitigation Fees.

Table 1 Number of Times Planned Flaring SOx Emissions in Specified Range, 2012-2016

Facility	>0.25	0.1 - 0.25	0.05 - 0.1	<0.05
	(tons/MMbbl)			
Chevron	1	3	1	0
Torrance Refinery*	3	2	0	0
Phillips 66	2	1	2	0
Tesoro – Carson	0	0	0	5
Tesoro – Wilmington	1	0	1	3
Valero	1	2	1	1

**Torrance Refinery has submitted a revision request for 2016 emissions.*

Staff is proposing to review the results of these Scoping Documents (potentially with the assistance of a technical consultant with expertise in refinery processes) and to evaluate further potential amendments that could be made to Rule 1118.

REGULATORY HISTORY

SCAQMD Rule 1118

On February 13, 1998, the SCAQMD Governing Board adopted Rule 1118 with the purpose of monitoring, recording and reporting data on refinery and related flaring operations. Upon rule adoption, the ~~AQMD~~ Board passed a resolution directing staff to a) collect and analyze the data submitted by subject facilities and determine if flare emissions are significant, and b) recommend whether further controls are needed.

After evaluating the data submitted to the SCAQMD from October 1, 1999 through December 31, 2003, staff compiled the "Evaluation Report on Emissions from Flaring Operations at Refineries", which was presented to the SCAQMD Governing Board on September 3, 2004. The report concluded that, although refineries had made important progress in reducing emissions since the rule was adopted, flare emissions, especially sulfur dioxide, were significant. The report recommended amending Rule 1118 to reduce emissions by minimizing flaring, treating flare vent gases and by refining the monitoring, reporting and emission calculation methodology in order to improve the data accuracy.

On November 4, 2005, the SCAQMD Governing Board amended Rule 1118 by requiring subject facilities to minimize or eliminate routine flaring from refining operations with flares and by establishing facility specific sulfur dioxide annual emission performance targets. Facilities exceeding the annual emission targets pay mitigation fees and submit a Flare Minimization Plan to the District for approval, subject to public review. The amended rule also mandates the use of continuous emission monitoring systems (CEMS) for total sulfur and monitor higher heating value of the vent gases combusted in flares in addition to monitoring vent gas flow. The amended rule also enacted enhanced monitoring, recordkeeping and reporting for flares at subject facilities.

As a result of all of these rule requirements, sulfur dioxide emissions from flares have been reduced in line with the declining annual emission performance targets that were reduced from 1.5 tons/MMbbl of crude capacity in 2006 to 0.5 tons/MMbbl of crude capacity by 2012.

SCAQMD 2012 AIR QUALITY MANAGEMENT PLAN

In May of 2014, a Technical Support Document based on the 2012 AQMP Control Measure – Multiple Component Source (MCS)-03 included an evaluation of potential emissions from refinery process units during startups or shutdowns that typically occur during process unit turnarounds. MCS-03 was planned for implementation in two phases. Phase I would include collection and review of emission impacts and operational procedures. Evaluation of Phase I data would lead to Phase II, which would involve identifying potential improved operating procedures and controls. This phased approach identified in MCS-03 is consistent with the proposed phased approach in the current proposed rulemaking.

The Technology Support Document recommended creating more Rule 1118 (c)(3) Flare Minimization Options and requiring facilities to annually review and revise Flare Minimization Plans to reduce flaring and flare emission during planned startup, shutdowns, and turnarounds. The Technology Support Document recommended amending Rule 1118 and requiring equipment upgrades and increased stringency in work practices and operational procedures to reduce flaring activity.

U.S. EPA Regulations

The U.S. EPA New Source Performance Standards (NSPS), under 40 CFR 60.18 – General Control Device Requirements, contains provisions for flare operations. The federal regulation requires flares to operate without visible emissions, to maintain a pilot flame present at all times the flare is in operation and observe certain limits for the net heating value and exit velocity of the gases being combusted. The regulation also requires monitoring of the flares to ensure that they are operated in compliance with these requirements.

In May 2007, U.S. EPA promulgated a new regulation, 40 CFR 60 Subpart Ja - Standards of Performance for Petroleum Refineries for which Construction, Reconstruction or Modification Commenced After May 14, 2007, which contains additional requirements to Subpart J for flares, including requiring a Flare Management Plan and root cause analysis for flare events with emissions exceeding 500 lbs SO_2.

In December 2015, the EPA issued a final rule for the Petroleum Refinery Sector Risk and Technology Review, New Source Performance Standards (NSPS), and National Emission Standards for Hazardous Air Pollutants (NESHAP) that further control emissions from petroleum refineries and provide important information about refinery emissions to the public and neighboring communities. The final rule has many requirements for refineries, but relevant to flares it seeks to eliminate smoking flare emissions and ensure high destruction efficiency of flare gases when they are released. Most requirements of this rule take effect on January 30, 2019.

On February 1, 2016 the Refinery Sector Rule became effective. Following the promulgation of the final rule, the EPA received three separate petitions for reconsideration of certain provisions of the final rule, including some that pertain in a limited way to flaring such as certain recordkeeping requirements, and the designation of a single smokeless design capacity for a flare.[7] These petitions are currently under review.

Work Practice Standards for Emergency Flaring

Well-operated flares used as air pollution control devices are expected to achieve a 98% Hazardous Air Pollutant (HAP) destruction efficiency. However, if vent gases being flared have insufficient heat capacity, or if the flare is not operated under appropriate conditions (e.g., over-steaming at the flare tip), EPA concluded that a 98% HAP destruction efficiency may not be achieved.

To ensure that the 98% HAP destruction efficiency was being met, EPA revised the NSPS, NESHAP, and MACT regulations to include two work practice standards for flaring. The first

[7] See the following link for further information regarding EPA's rule and the petitions for amendment. www.epa.gov/stationary-sources-air-pollution/petroleum-refinery-sector-risk-and-technology-review-and-new-source

work practice standard requires that flares operate with a continuously-lit pilot flame at all times when gases are sent to the flare, that a minimum net heating value in the combustion zone be maintained while flaring, and that refineries conduct additional monitoring and recordkeeping of flare operations.

A second work practice standard was established for flaring that occurs above a flare's smokeless capacity. In addition to the requirements from the first work practice standard, a flare management plan must be prepared detailing how a facility will minimize flaring, flaring above a flare's smokeless capacity must meet visibility and flare tip velocity limits, and if these limits are exceeded a root cause analysis and corrective action must be conducted. Violations of this second work practice standard occur when the smokeless capacity is exceeded and visibility or flare tip velocity limits are exceeded if: 1) any exceedance was caused by operator error or poor maintenance, or 2) two exceedances occur in any three year period and the exceedances have the same root cause (outside of force majeure), or 3) three exceedances occur in any three year period for any root cause (outside of force majeure).

SUMMARY OF PROPOSED RULE AMENDMENTS

The following amendments are proposed to Rule 1118. Each of these proposed amendments would be considered by the Governing Board for adoption as part of this first phase of rulemaking. Staff would act upon the information gained from these currently proposed amendments for a second phase of rulemaking. At this time, no language or concepts have been proposed for the second phase of rulemaking.

a. Purpose and Applicability

No changes are proposed in this section.

b. Definitions

The proposed rule has the following definitions amended, removed, or added to:

- "Clean Service Flare" – <u>Removed and replaced</u> with a definition for "Clean Service Stream" as follows:

"CLEAN SERVICE STREAM is a gas stream such as 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 if determined to be equivalent and approved in writing by the Executive Officer."

- Emergency Service Flare – Removed

- Essential Operational Needs – Removed flaring due to relief valve leakage and intermittent minor venting and removed emergency flare events from this definition

- Flare – Added two classifications of flares, "clean service" and "general service" as defined below:

"CLEAN SERVICE FLARE is a flare that is designed and configured by installation to combust

only clean service streams.
GENERAL SERVICE FLARE is a flare that is not a Clean Service Flare."

- Flare Events – Amended with some clarifying text and added a new provision that defines that multiple flaring episodes within a single day and attributable to the same cause are considered a single flare event:

"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."

- Flare Tip Velocity – Added

"FLARE TIP VELOCITY is the velocity of flare gases exiting a flare tip averaged over 15 minutes time periods, starting at 12 midnight to 12:15 am, 12:15 am to 12:30 am, and so on, concluding at 11:45 pm to midnight, and calculated as the volumetric flow divided by the area of the flare tip."

- General Service Flare – Removed

- Planned Flaring Event – Added

"PLANNED FLARING EVENT is any flaring as a result from process unit(s) startup, shutdown, turnaround, maintenance, and non-emergency flaring. Flaring from the planned startup of a process unit that is more than 36 hours after an unplanned shutdown of that same process unit shall be considered a Planned Flaring Event."

- Sampling Flare Event – Removed.

- Smokeless Capacity – Added

"SMOKELESS CAPACITY is the maximum vent gas flow rate or mass rate that a flare is designed to operate without visible emissions."

Web-Based Flare Event Notification System – Added
"*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. Requirements

The proposed rule has the following requirements that have been amended.

- All references to effective dates that have already passed (e.g., January 2006) have been removed and replaced with general text requiring facilities to operate flares in the same manner, but without specifying an effective date.

- A new requirement has been added that flares at petroleum refineries must be operated below a velocity of 60 feet per second, or the lesser of 400 feet per second and a calculated velocity using an equation from U.S. EPA's Refinery Sector Rule.

- A new requirement has been added that no later than January 30, 2019, the net heating value of the combustion zone (NHV_{CZ}) during flaring must be at or above 270 MMBTU per standard cubic foot, averaged over a 15-minute period. The EPA Refinery Sector Rule is incorporated by reference for the calculation of NHV_{CZ}.

- Specific Cause Analyses currently are required for flare events that exceed certain thresholds, except for planned start-ups, shut-downs, and turnarounds. A provision has been added to require Specific Cause Analyses *"for any flare event resulting from non-standard operating procedure during a planned shutdown, planned startup or turnaround"* to provide greater clarity about which events are subject to this requirement.

- Consistent with requirements in the U.S. EPA NESHAP, a requirement has been added for petroleum refineries that requires Specific Cause Analyses when the smokeless capacity of the flare is exceeded and either the visibility or flare tip velocity limit is exceeded, with an effective date of January 30, 2019.

- The timeline for facilities to submit a Specific Cause Analysis has been removed from section (i) Notification and Reporting Requirements and added in this section. The ability for facilities to request an extension up to 30 days beyond the original 30-day submission date has also been shortened to 15 days, to be consistent with the 45-day period facilities are provided to submit a root cause analysis under the U.S. EPA NESHAP.

- A new provision has been added, consistent with the U.S. EPA NESHAP that requires facilities to complete the corrective action identified in Specific Cause Analyses within 45 days of the flare event or a longer period that is justified and as soon as practicable. The Executive Officer may require a modified schedule for corrective actions beyond 45 days.

- Consistent with requirements in the U.S. EPA NESHAP, a requirement has been added for petroleum refineries that prohibits flaring above the smokeless capacity of the flare when either visibility or flare tip velocity limits are exceeded if:
    - A single flare event is caused by poor maintenance or operator error, or
    - Two flare events are found to have the same cause in any three year period as determined by a Specific Cause Analysis, or
    - Three flare events occur in any three year period from any cause.

The visibility limits already in Rule 1118 are consistent with U.S. EPA NESHAP visibility limits, however this requirement has been expanded to also include the limits in SCAQMD Rule 401 as this visibility standard is also used for determining compliance by SCAQMD inspectors during flaring events.

- A new requirement has been added requiring facilities to submit a Scoping Document 12 months after rule adoption that includes:
    - An analysis of two alternatives to reduce Planned Flaring Events for each of three annual performance targets. The three performance targets are 0.10, 0.05, and 0.01 or lower tons of SOx per million barrels of crude processing capacity, and 0.1 tons of VOC per year from clean service flares. The Scoping Document must analyze the potential controls, technical feasibility, approximate cost, and timing constraints to implementing each of these alternatives as soon as feasible.
    - An analysis of how a facility can reduce emissions from Unplanned Flare Events caused by four scenarios; 1) a sudden influx of vent gas into the flare gas header, 2) a sudden

loss of the process unit with the highest fuel gas consumption rate of recovered flare gas, 3) a sudden loss of all externally generated electrical power, 4) a sudden loss of internally generated electrical power. Existing systems (such as flare gas recovery systems) may count towards the three alternative requirement.

  - A description of the components of the flare system. Some portions of this description were previously required as part of a Flare Minimization Plan, but have now been moved into the Scoping Document, and added to in order to account for additional requirements in other parts of PAR 1118 (such as smokeless capacity).

- Requirements regarding the effective date to install flare gas recovery and treatment systems have been removed as all facilities subject to this provision have already installed these systems under the current version of the rule.

d. Performance Targets

Petroleum Refineries are required to reduce sulfur dioxide emissions from flares to less than 0.5 tons per million barrels of crude processing capacity averaged over one year. The proposed amended rule also removes outdated compliance deadlines and removes the Mitigation Fee annual cap of $4,000,000.

e. Flare Minimization Plan

Minor clarifying text has been added, and one provision requiring a detailed process flow diagram has been moved to the requirements for a Scoping Document and also the Flare Monitoring and Recording Plans (FMRP).

f. Flare Monitoring and Recording Plan Requirements

Outdated administrative deadlines and alternative sampling requirements have been removed. Detailed process flow diagrams that were previously required in a Flare Minimization Plan are now required in the FMRP instead, with some modifications. The detailed process flow diagram is only required for control equipment, while a representative flow diagram is required for connections to process units. Also, unless monitoring instruments already required in Rule 1118 are modified, the FMRP does not have to be updated with new instruments required by the EPA Refinery Sector Rule.

g. Operation, Monitoring, and Recording Requirements

Outdated deadlines, provisions regarding alternative sampling, and tables have been removed. Monitoring requirements in the EPA Refinery Sector Rule that are supplemental to existing requirements in Rule 1118 have been incorporated by reference. Video monitoring requirements have been updated to now require recording at no less than one frame every 15 seconds. For all flares the recording must include the flare and an area above the flare sufficient for visible emissions and flame observations.

h. Recordkeeping Requirements

The requirement to keep video records for a minimum of 90 days has been updated to five years.

i. Notification and Reporting Requirements

Outdated administrative deadlines have been removed and references have been updated. A new requirement has been added to submit flaring notifications via the Web-Based Flare Event Notification System, and will only use telephone notification if the web-based system is unavailable. A new notification requirement has been added that if the cumulative daily total of flare vent gas from a flare exceeds 100,000 standard cubic feet, the facility is required to notify the SCAQMD via the Web-Based Flare Event Notification System. Staff is proposing to maintain the thresholds used for the District's public notification regarding flare events. A new requirement has also been added for facilities to submit quarterly reports of data from new monitoring requirements in PAR 1118 and the EPA NESHAP as soon as it becomes available, or on January 30, 2019, whichever is earlier.

j. Testing and Monitoring Methods

Outdated administrative deadlines and sections have been removed and updated American Section of the International Association for Testing Materials, (ASTM) methods have been incorporated.

k. Exemption

A new exemption has been added so that events outside of the operator's control (i.e. external power disruptions, natural disasters, and acts of war/terrorism) do not count towards the new prohibitions listed in paragraph (c)(10). The (c)(10) prohibitions include the new 'three strikes' requirement imposed by the EPA NESHAP. This new exemption in PAR 1118 is also consistent with the requirements in the EPA NESHAP.

l. Attachment B

Emission factors for vent gas, propane, and butane combustion have been updated using current guidance from EPA's AP-42 chapters 1.5 and 13.5. <u>Clarifying text was added to Attachment B after the Set Hearing version of PAR 1118 was released that indicates that facilities can use alternative calculation methods only if those methods are supported by facility-specific data, such as monitoring and/or gas composition data.</u>

COMPARATIVE ANALYSIS

As required by Health and Safety Code Section 40727.2, the purpose of this analysis is to identify and compare any other SCAQMD or federal regulations that apply to the same equipment or source type.

The proposed amended Rule 1118 was amended as to not conflict with National Emissions Standard for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart CC. On July 2016 the U.S. EPA promulgated the most recent amendments to the Refinery Sector Rule (RSR) in NESHAP under the authority of CAA, section 112. The RSR NESHAP applies to Petroleum Refinery flares and the proposed amended rule has incorporated sections of the RSR to maintain equivalency with the federal standard for flares. Table 2 below shows a comparison with the proposed amended rule and subpart CC in areas where the PAR has incorporated sections of the RSR.

TABLE 2 - Comparison – PAR 1118 with EPA Refinery Sector Rule (RSR) [Part 63 Subpart CC]

Amended Rule Element	1. PAR 1118 Amendments	2. EPA RSR
Flare Tip Velocity	-Maintain velocity below 60 feet per second, or lesser of 400 feet per second or calculation based on net heating value of vent gas	-Same as PAR 1118.
Net Heating Value in Combustion Zone (NHV_{CZ})	-Maintain NHV_{CZ} above 270 BTU/scf. Incorporates by reference EPA RSR calculations.	-Same as PAR 1118.
Specific Cause Analysis (SCA)	-SCA required for flare events above VOC or SOx or vent gas threshold for unplanned flare events and non-standard operating procedures from planned flare events. -SCA required when flaring occurs above smokeless capacity of flare and visibility or flare tip velocity limit is exceeded. -SCA due within 30 days with potential for 15 day extension -Corrective action required within 45 days with option to request extension from Executive Officer.	-No equivalent emissions or vent gas flow rate threshold requirement for SCA known as “root cause analysis” in EPA RSR -SCA requirement same in EPA RSR for flaring above smokeless capacity of flare. -SCA due in 45 days -Corrective action required in 45 days or as soon as practicable.
Scoping Document	-Facilities must prepare a Scoping Document that evaluates feasibility of minimizing or avoiding Planned and Unplanned Flare Events, using specific criteria. Information from Scoping Documents will be used for subsequent rulemaking.	-Facilities must develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases.
Removal of Annual Cap on Mitigation Fees	-Petroleum refineries must pay fees on flaring emissions above a performance target of 0.5 tons per million barrels of crude capacity. The cap on these fees would be removed.	-No similar requirement.
Flare Monitoring and Recording Plan (FMRP)	-Facilities must submit 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.	-Facilities must submit in their Flare Management Plan a simple process flow diagram showing the locations of the following components of the flare: flare tip; knockout or surge drum(s) or pot(s); flare header(s) and subheader(s); assist system; ignition system; and all gas lines (including flare waste gas, purge or sweep gas, and supplemental gas) that are associated with the flare.
Flare Monitoring Requirements	-Facilities must monitor flares continuously for gas flow, continuously for heating value, and	-RSR also requires continuous monitoring for gas flow, heating

	semi-continuously for sulfur content. -Clean service flares may calculate the higher heating value and/or their sulfur content instead of monitoring. -For any flare monitoring that is different than what is required by this rule, the EPA RSR has been incorporated by reference (e.g., steam assist).	values and semi-continuously for sulfur content. -RSR is inapplicable to clean service flares. PAR has wider scope in terms of types of flares.
Video Recording	-Facilities must monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare, the flame of elevated flares, and a sufficient area above the flame of all flares that is suitable for visible emissions observations, at a rate of no less than four frames per minute.	-Facilities must use a color video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the flare flame and a reasonable distance above the flare flame at an angle suitable for visual emissions observations.
Notification	-Facilities must notify the District via a web-based system if a flare event exceeds 100 pounds of VOC, 500 pounds of SOx, or 500,000 scf of vent gas, and if the cumulative daily total vent gas exceeds 100,000 scf.	-No similar requirement
Emissions Reporting	-Facilities must report quantified flaring emissions quarterly to the District using emission factors that are consistent with EPA's AP-42 guidance.	-No similar requirement.

EXPECTED EMISSIONS IMPACT

PAR 1118 affects 31 flares at 12 facilities, all located in Los Angeles County. The proposed amendments to this rule will prohibit repeated smoking flaring events, excluding Force Majeure events, which tend to produce the highest emissions from flaring. PAR 1118 also requires a minimum net heating value in the combustion zone, ensuring that when flaring does occur that the destruction efficiency should be at least 98%. These prohibitions and limitations are consistent with federal requirements.

An updated emission factor for VOCs that is about ten times higher than the previous emission factor will increase the emissions inventory for each facility, assuming that their flaring is not reduced by more than a factor of ten. Although the inventory will show an increase for VOC emissions, this is not a reflection of an expected increase in emissions, rather it is an improvement in the understanding of emissions from this source.

Consistent with the EPA Refinery Sector Rule, PAR 1118 should also reduce emissions from all pollutants due to the new prohibitions on repeated flaring events above the smokeless capacity which were not caused by Force Majeure, and the new limits on flare tip velocity below the smokeless capacity that are designed to improve combustion efficiency. The level of emissions reductions cannot be quantified because there are new criteria and monitoring requirements used to determine the future level of emissions that were not used in previous estimates.

WEB-BASED FLARE EVENT NOTIFICATION SYSTEM

The District currently maintains a web-based Flare Event Notification System that facilities can use to satisfy the notification requirements of the existing rule. Facilities also currently use telephone notification instead of the web-based system in some instances. With the updated notification requirements proposed in the rule, the web-based system will need to be upgraded to handle the new requirements. This funding action that is being proposed to the Governing Board, when passed, will transfer up to $100,000 from the Rule 1118 Mitigation Fund into the District's general fund for the purpose of upgrading the District's web-based Flare Event Notification System. A Board-approved software development contractor will be utilized to conduct this work.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

Pursuant to the California Environmental Quality Act (CEQA) and SCAQMD Rule 110, the SCAQMD, as lead agency for the proposed project, has reviewed the proposed amendments to Rule 1118 and the subsequent spending of up to $100,000 to update the web-based Flare Event Notification System pursuant to: 1) CEQA Guidelines § 15002(k) - General Concepts, the three-step process for deciding which document to prepare for a project subject to CEQA; and 2) CEQA Guidelines § 15061 - Review for Exemption, procedures for determining if a project is exempt from CEQA.

As provided in CEQA Guidelines § 15306 - Information Collection, the proposed project is exempt because it will consist of basic data collection, research and resource evaluation activities and will not result in a serious or major disturbance to an environmental resource. CEQA Guidelines §15306 exempts such a project for information-gathering purposes, or as part of a study leading to future action which the agency has not yet taken. Furthermore, SCAQMD staff has determined that it can be seen with certainty that there is no possibility that the proposed project may have a significant adverse effect on the environment. Therefore, the project is considered to be exempt from CEQA pursuant to CEQA Guidelines § 15061(b)(3) – Activities Covered by General Rule. A Notice of Exemption will be prepared pursuant to CEQA Guidelines § 15062 - Notice of Exemption. 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.

SOCIOECONOMIC IMPACT ASSESSMENT

PAR 1118 Phase I would affect 12 facilities operating a total of 31 flares. Eight out of 12 are refinery facilities which belong to the sector of petroleum refineries [North American Industrial Classification System (NAICS) 324110]. And of the remaining four; the one sulfur recovery plant and three hydrogen production plants belong to the sector of industrial gas manufacturing (NAICS 325120). All the affected facilities are located in Los Angeles County and none are small businesses.

The purpose of the proposed amendments (Phase I) is to gather more information and update the existing rule with federal requirements. Two proposed amendments could potentially have cost impacts. PAR 1118 would require the affected facilities to prepare a Scoping Document that evaluates the feasibility of reductions of emissions from planned and unplanned flaring events, and also would remove the $4 million annual cap on mitigation fees when a facility's SOx emissions exceed a Performance Target.

One-Time Cost of Scoping Documents

While the affected facilities have not been required by SCAQMD to prepare a scoping document before under the existing rule 1118, the cost is expected to be similar to other plans required by other rules such as flare monitoring and reporting. Based on staff's phone discussion with a refinery representative on May 18, 2017 and a refinery consultant on May 3, 2017, each scoping document may take about 50-70 hours of staff time and may require the hiring of outside consultants to prepare. Based on the number of flares located in each affected facility, the one-time cost of preparing a scoping document is estimated to be about $50,000 for a non-refinery facility and $250,000 for a refinery facility.~~, respectively.~~ As a result, the total one time cost of preparing scoping documents is estimated at $2.2 million (4*$50,000+8*$250,000) for all the facilities.

Table 1 has the distribution of the annualized cost by industry. The one-time cost of the PAR 1118 is annualized over a typical 10-year equipment life using a four percent real interest rate*. Petroleum Refineries would absorb about 90 percent (or $246,000) of the $270,600 estimated annual cost. In addition, PAR 1118 could potentially increase the number of Specific Cause Analysis reports due to increase in the frequency of flaring events occurring at the new VOC emission limits. However, the additional costs of preparing these extra reports are expected to be minimal.

Table 1
Estimated Annual Cost of Compliance (2017 dollars)

Industry (NAICS)	One-Time Costs Annualized Over 10 Years
Petroleum Refineries (324110)	$246,000
Industrial Gas Manufacturing (NAICS 325120)	$24,600
Total	**$270,600**

*Capital recovery factor for 10 years and four percent real interest rate is 0.123. Annualized cost over 10 years is calculated as ($2.2 million*0.123 = $270,600).

Mitigation Fees

Under the existing rule, facilities must pay a Mitigation Fee if their SOx emissions exceed a Performance Target. In 2012, this Performance Target was established at 0.5 tons of SOx emissions per million barrels of crude oil processing capacities. The affected facilities would pay a ratcheted mitigation fee when their SOx emissions exceed the Performance Target by up to 10 percent; between 10 and 20 percent; and above 20 percent. The mitigation fees are currently capped at $4 million per year.

PAR 1118 would remove the $4 million annual cap on mitigation fees when a facility's SOx emissions exceed the Performance Target. The removal of $4 million cap could potentially impose additional costs on affected facilities. Past performance records (2012-2016) for the 12 facilities show that only one facility in 2015 would have exceeded the $4 million cap ($7.7 million) due to an explosion which caused a shutdown and subsequent atypical operations for the remainder of the year. A second instance where a facility had a bypass valve that was unmonitored also exceeded the annual cap (this bypass valve has since been remove from service). Therefore, it is unlikely that the affected facilities would exceed the annual cap and pay more than $4 million of mitigation fees.

Since the overall annualized cost impacts of PAR 1118 is estimated at $270,600, the Regional Economic Impact Model (i.e., the REMI Policy Insight model) is not used. It has been a standard socioeconomic practice that, when the annual compliance cost is less than one million current U.S. dollars, REMI is not used to simulate jobs and macroeconomic impacts, because the resultant impacts would be diminutive relative to the baseline regional economy.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE

Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the hearing. The draft findings are as follows:

Necessity – PAR 1118 is needed to further reduce emissions from flaring, to gather more information about the emissions from flaring, and to update outdated administrative requirements in the rule.

Authority - The SCAQMD Governing Board obtains its authority to adopt, amend, or repeal rules and regulations from Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, and 41508.

Clarity – The amendments to PAR 1118 are written and displayed so that the meaning can be easily understood by persons directly affected by them.

Consistency – PAR 1118 is in harmony with EPA's Refinery Sector Rule, and not in conflict with or contradictory to, existing statutes, court decisions, federal or state regulations.

Non-Duplication – Portions of the proposed amendments in PAR 1118 incorporate explicitly or by reference some federal NESHAP requirements that fall within the criteria and requirements in Health and Safety Code §40727.2(g). The remaining proposed amendments to PAR 1118 do not impose the same requirement as any existing state or federal regulation, and the proposed amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, the SCAQMD.

Reference - In adopting these amendments, the SCAQMD Governing Board references the following statutes which the SCAQMD hereby implements, interprets or makes specific: Health and Safety Code Sections 40001 (rules to achieve ambient air quality standards), 40440(a) (rules to carry out the Air Quality Management Plan), and 40440(c) (cost-effectiveness), 40725 through 40728 and Federal Clean Air Act Sections 171 et seq., 181 et seq., and 116.

COMMENTS AND RESPONSES

A public workshop was held on May 11, 2017 in which approximately 25 people attended. Participants provided comments at the meeting and eight comment letters or emails have also been received. The following section includes comments received and staff's responses.

Comment Number	Commenter	Comment Date
1	Air Liquide	5/10/2017
2	Air Products	5/18/2017
3	Air Products	5/23/2017
4	Air Products	6/1/2017
5	Communities for a Better Environment (CBE)	5/9/2017
6	Communities for a Better Environment (CBE)	5/19/2017
7	Communities for a Better Environment (CBE)	6/2/2017
8	Communities for a Better Environment (CBE)	6/5/2017
9	Torrance Refinery	6/2/2017
10	Western States Petroleum Association (WSPA)	5/10/2017
11	Western States Petroleum Association (WSPA)	6/2/2017
PWS	Public Workshop Comments	5/11/2017

Air Liquide

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May 10, 2017

Topic / Ref. : Rule 1118 Proposed Changes

We are writing in regards to the proposed changes to Rule 1118 and the effects it may have upon our hydrogen production facility located in El Segundo. We would also like to make a recommendation we believe would be beneficial to the District. Environmental stewardship is one of our core values, and Air Liquide is proud to be the lowest emitting Rule 1118 facility.
Our facility utilizes an enclosed ground flare (EGF) for the safe consumption of certain produced process gases during startup, shutdown, or process upsets. Synthesis gas (syngas) is a mixture of hydrogen, carbon monoxide, carbon dioxide, steam, and small amounts of unreacted methane produced by the steam reforming of methane that is present as an intermediate after reforming and before purification. It is a process stream inherently devoid of sulfur and VOCs. Syngas, along with pure hydrogen, and off-gas, the leftover products from syngas that are removed during purification, are the three streams that are capable of being combusted in our EGF. It is classified as a clean service flare. 1-1

EGFs by design shield the flame inside an enclosure to prevent radiant heating of the surroundings and emission of visible light and noise. While camera observation of the air above the flare for opacity is certainly feasible, the direct observation of the flame is not reasonably possible without placing a camera in the line of fire and subjecting it to damage during a flare event.

The wording of proposed 1118{g}{6) requires the capture of digital images of both the flare and flame. We ask that clean service EGFs be exempted from the requirement to capture an image of the flame. To support that we ask that the district add a definition for an EGF as separate and distinct from a conventional tower or open ground flare. 1-2

We understand that some of the language in the proposed rule 1118 was adopted from 40 CFR 63.670 (as part of NESHAP CC) and specifically the aforementioned requirement was paraphrased from 40 CFR 63.670(h)(2) with additional district requirements added. However our facility is not within the scope of NESHAP CC, so we conclude that excepting an EGF combusting only streams not regulated under NESHAP CC (i.e. clean service flares) will not pose any conflicts with the EPA rules. 1-3

We also request clarification of the language found in the proposed 1118(c)(13) which requires the preparation of a Scoping Document to state that it applies to petroleum refineries only. While the context of 1118(c)(13)(B) leads one to the conclusion that it is intended for petroleum refineries and not hydrogen or sulfuric acid plants since they 1-4

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Air Liquide

do not process petroleum, the reader would be best served by a clear top-line explanation that 1118(c)(13) is applicable only to petroleum refineries. We would like to remind the staff that the presentation given at the Governing Board Special meeting of March 9, 2017 made sole mention of refineries. The other two source categories were not addressed, thus we conclude no board mandate was given to implement any additional regulation upon hydrogen producers. 1-4 cont'd

Rule 1118.1, for the control of non-refinery flares, is on the rulemaking calendar for later this year. Presumably it would regulate flares at landfills, wastewater treatment plants and the like. We would appreciate if the District would consider that a hydrogen facility's flare is far more akin to the types of facilities that would be regulated in 1118.1. Namely, they all combust a low BTU stream that does not contain HAPs, and use similar control devices such as enclosed ground flares. We ask the District to regulate non-refinery facilities with flares such as ours under the new rule 1118.1 instead of the proposed rule 1118. 1-5

We appreciate the District's efforts in this matter and ask the District to give due regard to our comments.

Regards,

Eric KLEINSCHMIDT

Response 1-1
Thank you for your comment. Please refer to responses 1-2 through 1-5 for specific responses.

Response 1-2
Paragraph (g)(7) of the rule has been modified to only require recording of a flare's flame if it is not enclosed.

Response 1-3
The new sections of the rule pertaining to the recently updated NESHAP have been amended to only apply to general service flares operating at petroleum refineries, including paragraphs (c)(3), (c)(4), and (g)(9).

Response 1-4
The Scoping Documents required by paragraph (c)(13) must be submitted by all facilities subject to the rule, including hydrogen plants. However, a Scoping Document can simply state what the facility is already doing to meet the goals specified in (c)(13) if the facility is already meeting or exceeding them. Also, the commenter is correct that hydrogen plants were not specifically mentioned in the single slide that summarized proposed amendments to Rule 1118 given to the Governing Board at its March 9, 2017 meeting. However, this presentation was not intended to provide a comprehensive analysis of all proposed amendments in the rule as that discussion is presented to the Board in rule-specific agenda items at the Stationary Source Committee (i.e., May 19, 2017, June 16, 2017) and at the Governing Board public hearing for rule adoption (set for July 7, 2017). As one of the purposes of the rule is to minimize flaring emissions from all facilities subject to the rule, it is appropriate that the Scoping Documents should be prepared by all facilities subject to the rule.

Response 1-5
During the rule-making process for 1118.1 and potentially during the second phase of rulemaking for PAR 1118, staff will evaluate whether it is appropriate to include flares from hydrogen plants within 1118.1. Because Proposed Rule 1118.1 has not yet been adopted, nor has draft rule language been released, it is premature to exempt hydrogen flares from Rule 1118.

From: Reebel,James C. <REEBELJC@airproducts.com>
Sent: Thursday, May 18, 2017 10:56 AM
To: Ian MacMillan; Dairo Moody; Eugen Teszler
Subject: Air Products Comments on Proposed Rule 1118 Language

Ian/Dairo/Eugene,

Thank you for taking the time to discuss some of our comments/concerns last week re: the proposed Rule 1118 language. As indicated, I wanted to provide 'official' comments/questions in writing for Air Products' Carson and Wilmington Hydrogen (H2) Plants:

- (b)(3)(C) – We discussed and it was noted that venting of clean service streams to a flare is considered and 'Essential Operational Need' (EON). A questions I have is that for facilities like AP Carson and Wilmington where all the streams that could be flared are considered clean service streams, would/should all flaring be considered as EON and how should this situation be represented on quarterly flare reports when assigning a relative cause to the flare event that the District relies on for its metrics/data to support these rule amendments? 2-1
- (b)(15) – We discussed the definition of 'Planned Flare Event' and staff clarified that unplanned flare events can still be longer than 24 hours and that the intent here was to address, along with section (i)(3), flaring emissions associated with the re-starts/startups themselves. 2-2
- (c)(6) – We discussed whether there was need for more specifics around the term 'non-standard operating procedure' in relation to when an SCA would be required for flaring that occurred as a result of any 'non-standard operating procedure' and my understanding was that the District does not intend to collect information on operating procedures or the procedures themselves and the facilities will be left to their own determination (subject to audit/inspection) whether flaring occurred due to something that was 'non-standard'. 2-3
- (c)(13)(B) – We would ask the District to either create target levels that both refineries and H2 plants can work with or separate target levels for H2 plants (i.e. SOx, million barrels of crude processing capacity). 2-4
- (c)(13)(C) and (C)(i) – Section (c)(13)(C) speaks to reducing flaring emissions during emergency (i.e. breakdowns, malfunctions, power disruptions, etc.) flaring events; however, subsection (c)(13)(C)(i) speaks to alternatives to avoid flaring which would imply alternatives to accomplish an elimination of flaring altogether. We would ask District to reword to make it more clear what is being requested (ideally alternatives for reductions and/or elimination of flaring and related emissions). 2-5
- (c)(14) and (c)(15) – There was an error within an item listed as (c)(13)(C)(vi) we discussed that it sounds like you are aware of and are correcting. 2-6
- (f)(3) – Although this language existed previously, we would suggest some addition that would clarify that the 'starting or restarting operations' means for a new or facility that has not been operated in some time; not to be confused with a start/restart of operations from a planned or unplanned maintenance outage/turnaround. 2-7
- (g)(7) – We discussed this and I expressed some apprehension in going from 1 fpm to 1 fps; however, upon further review I determined that we are currently recording at 3 fps so we would not have an issue with complying with the increased framerate requirement. We did also discuss the use of the phrase 'angle above' which staff indicated was meant to mean angle the camera to point above the flare (where visible emissions, if any, would occur) vs. placing the camera itself at an angle above the flare; and we feel clarification is needed to ensure there is no confusion. 2-8

- (i)(2) –It is unclear to us, as H2 facilities that vent only clean service streams to our clean service flares, whether we would need to comply with this requirement moving forward as subparagraph (b)(3)(C), venting of clean service streams, was omitted. Furthermore, as touched on above with regards to section (b)(3)(C), we would ask for clarification whether we should be designating all clean service flaring as only EON moving forward, regardless of whether routine venting or due to an emergency, shutdown/startup, maintenance, etc.? If this section does apply and everything is not intended to be labeled as EON, we would be concerned that the elimination of a previous 500,000 SCF notification threshold could create a significant, increased burden on our operations team to not only make these notifications much more frequently but more importantly to define whether any minor flaring that occurred beyond 'normal EON flaring' is attributable to an emergency (i.e. breakdowns, malfunctions, power disruptions, etc.) within the allowable 1-hour window. We also discussed that current practice would dictate that an accompanying breakdown notification would need to occur along with any unplanned, emergency flaring notification. This would create a significant, additional burden for both our operations and environmental staff (to perform notifications and complete/submit breakdown reports within 7 days) and District inspectors (to respond to potential magnitude(s) increase in breakdown notifications including review of reports and any follow-up needed). 2-9
- (i)(3) – We discussed and we shared concerns that were raised at Working Group Meeting #3 re: how this language maybe should be looked at closer, in conjunction with (B)15), to ensure that facilities aren't faced with potential startup delays based on timing of any required notification. 2-10
- Attachment B, Section 1 – We discussed the need to add additional tables or clarify regarding (1) sulfur-free streams which account for 3/4 of the clean service streams at Carson plant and 4/5 of the clean service streams at Wilmington plant and (2) H2 combustion which only generates NOx emissions. We think putting this in the these tables in some manner (i.e. additional tables, footnotes, etc.) would help in alleviating some concerns about clean service flaring that occurs at H2 plants (and what makes them clean) by providing a clear example of emissions that don't occur (i.e. no SOx for many, NOx only for H2). 2-11

Let me know if any questions or if you would like to discuss any of our concerns in further detail to ensure those concerns are understood and, as possible, addressed. Appreciate your understanding and cooperation!

Jim Reebel
Principal Environmental Engineer
Air Products and Chemicals, Inc. Los Angeles Area

Mobile: (714) 642-4252
Office: (310) 847-7300 x13
Fax: (310) 847-7311
Email: reebeljc@airproducts.com

Response 2-1
Clean service streams are classified as Essential Operational Need pursuant to clause (c)(3)(C) of PAR 1118, and should be reported as such in quarterly reports. However, if emergencies occur, even at a flare that only has clean service streams, they should be categorized as emergencies on quarterly reports.

Response 2-2
Paragraph (b)(15) has been clarified such that a Planned Flare Event will be separate from an Unplanned Flare Event if it begins more than 36 hours after then end of the Unplanned Flare Event from the same process unit that is starting back up. Paragraph (i)(3) has been modified, and paragraph (i)(4) has been added such that a single notification is now required if the cumulative daily total of vent gas exceeds 100,000 SCF.

Response 2-3
The comment is correct.

Response 2-4
Clause (c)(13)(B)(iv) has been added that includes a new emission level based on VOC emissions per year, instead of SOx emissions per MMbbl of crude capacity. For facilities that do not process crude, such as hydrogen plants, the emissions levels in clauses (c)(13)(B)(i) through (iii) do not need to be analyzed.

Response 2-5
Subparagraph (c)(13)(C) has been modified to provide more clarity and to add specific scenarios that should be analyzed in the Scoping Document for Unplanned Flaring.

Response 2-6
The numbering error noted in the comment has been corrected.

Response 2-7
Paragraph (f)(3) has been modified as requested.

Response 2-8
Paragraph (g)(7) has been modified to only require 4 frames per second, and the area that needs to be recorded (as opposed to the 'angle') has been clarified.

Response 2-9
Notification requirements in (i)(2), (i)(3), and (i)(4) have been modified. The requirement to notify the District for unplanned events greater than 500,000 scf remains, and is still applicable to all facilities subject to Rule 1118. As noted in Response 2-1, emergencies at hydrogen plants should be reported as such in quarterly reports, and for notification purposes under (i)(2) too. If a facility needs to file a Rule 430 breakdown notice, they can continue to do so where appropriate. A simpler requirement has been added in (i)(4) that requires a single notification to the District if the daily cumulative vent gas totals more than 100,000 scf. This notification does not require a Rule 430 breakdown report, unless the facility feels it is necessary to provide protection for potential violations that may occur due to a breakdown.

Response 2-10
Paragraphs (i)(3) and (4) have been modified to only require a single notification if the daily cumulative vent gas totals more than 100,000 scf.

Response 2-11
Clarification has been added to Attachment B. See also Response 3-1

From: Reebel,James C. <REEBELJC@airproducts.com>
Sent: Tuesday, May 23, 2017 1:16 PM
To: Ian MacMillan
Cc: Dairo Moody; Eugen Teszler
Subject: FW: Info Request - H2 Combustion Emissions

Entire e-mail chain is one comment.
3-1

Ian,
Some info I was able to obtain; let me know if you would like to discuss…
thanks! Jim

From: Hendershot,Reed J.
Sent: Tuesday, May 23, 2017 11:45 AM
To: Reebel,James C. <REEBELJC@airproducts.com>
Cc: Kloosterman,Jeffrey W. <KLOOSTJW@airproducts.com>; Govert,Scot C. <GOVERTSC@airproducts.com>; Sauers,Michael J. <SAUERSMJ@airproducts.com>
Subject: RE: Info Request - H2 Combustion Emissions

I think that it is a fair comparison. If you have flare pilot estimate using natural gas, then you could use these numbers to ratio the estimate for a flare pilot. I don't know the specifics of your flare pilot, but in general I would consider a pilot to be more similar to the "Uncontrolled" emissions since they are designed for stability over NOx.

Let me know if you want to discuss any more specifics on it. Reed

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From: Reebel,James C.
Sent: Tuesday, May 23, 2017 1:23 PM
To: Hendershot,Reed J. <HENDERR2@airproducts.com>
Cc: Kloosterman,Jeffrey W. <KLOOSTJW@airproducts.com>; Govert,Scot C. <GOVERTSC@airproducts.com>
Subject: RE: Info Request - H2 Combustion Emissions

So air districts question is with regards to combustion of H2 stream in a flare… any idea if this would be treated/viewed any differently than the info you provided or is it a fair approximation (i.e. burners vs. flare pilots)? Thanks for your help!

Jim

From: Hendershot,Reed J.
Sent: Tuesday, May 23, 2017 10:12 AM
To: Reebel,James C. <REEBELJC@airproducts.com>
Cc: Kloosterman,Jeffrey W. <KLOOSTJW@airproducts.com>; Govert,Scot C. <GOVERTSC@airproducts.com>
Subject: RE: Info Request - H2 Combustion Emissions

Hi Jim,

In answer to your question on NOx for H2 use, we did have to do something similar for our emissions permit for our combustion test furnaces here in Allentown. The reference that I used for that is from the John Zink Combustion Handbook on page 193 which references EPA- 453/R- 93- 015 which I was able to find on page 19 here https://nepis.epa.gov/Exe/ZyNET.exe/2000HIWU.txt?ZyActionD=ZyDocument&Client=EPA&Index=1991%20Thru%201994&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5CZYFILES%5CINDEX%20DATA%5C91THRU94%5CTXT%5C00000014%5C2000HIWU.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=19.

The table in the document is attached.

TABLE 2-1. UNCONTROLLED EMISSION FACTORS FOR MODEL HEATERS

Model heater type	Uncontrolled emission factor, lb/MMBtu		
	Thermal NO_x	Fuel NO_x	Total NO_x[a]
ND, natural gas-fired[b]	0.098	N/A	0.098
MD, natural gas-fired[b]	0.197	N/A	0.197
ND, distillate oil-fired	0.140	0.060	0.200
ND, residual oil-fired	0.140	0.280	0.420
MD, distillate oil-fired	0.260	0.060	0.320
ND, residual oil-fired	0.260	0.280	0.540
ND, pyrolysis, natural gas-fired	0.104	N/A	0.104
ND, pyrolysis, high-hydrogen fuel gas-fired[c]	0.140[d]	N/A	0.140

[a]Total NO_x = Thermal NO_x + Fuel NO_x
[b]Heaters firing refinery fuel gas with up to 50 mole percent hydrogen can have up to 20 percent higher NO_x emissions than similar heaters firing natural gas.
[c]High-hydrogen fuel gas is fuel gas with 50 mole percent or greater hydrogen content.
[d]Calculated assuming approximately 50 mole percent hydrogen.
N/A = Not applicable.

2-3

The table references a "high- hydrogen fuel gas" and note c states that it is "50 mole percent or greater hydrogen content." In addition note b states that "refinery fuel gas with up to 50 mole percent hydrogen can have up to 20 percent higher NOx emissions than similar heaters firing natural gas." I think that based on the specifics of your case you should be able to use these footers and the emission factors to help answer the questions asked by the air district.

Please note that this table is for "Uncontrolled" emissions and therefore should be similar to a worst case scenario since most contemporary burners are at least partially low NOx.

For reference, the title page of the EPA document is here: https://nepis.epa.gov/Exe/ZyNET.exe/2000HIWU.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1991+Thru+1994&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C91thru94%5CTxt%5C00000014%5C2000HIWU.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&Z yPURL.

In addition as an FYI, since Jimmy's departure, Jeff Kloosterman and myself are supporting HYCO activities now from a combustion point of view.

Let us know if you have any additional questions. Reed

From: Reebel,James C.
Sent: Monday, May 22, 2017 7:42 PM
To: Morris,Paul J. <MORRISPJ@airproducts.com>; Adams,Keith B. <ADAMSKB@airproducts.com>; Sauers,Michael J. <SAUERSMJ@airproducts.com>; Govert,Scot C. <GOVERTSC@airproducts.com>; Li,Jimmy Xianming <LIXM@airproducts.com>
Subject: Info Request - H2 Combustion Emissions

Gentlemen,

I am working with local air district staff on some proposed updates to our local flare rule and a question came up whether we had knowledge of or have utilized any emission factors (ideally w/ references) for hydrogen combustion. Have any of you come across anything or can share how you calculate any emissions from H2 combustion? My understanding is that theoretically the only emissions should be water; however, in reality due to flame characteristics you will get some amount of NOX formation (currently we just utilize a default NOx emission factor for H2 combustion; no other pollutant emissions). Please let me know by Wednesday if you could … thanks for the help!

Jim Reebel
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Email: reebeljc@airproducts.com

Response 3-1
A footnote has been added to the Vent Gas table in Attachment B that for pure hydrogen streams, only the NOx emission factor should be used.

From: Reebel,James C. <REEBELJC@airproducts.com>
Sent: Thursday, June 1, 2017 3:37 PM
To: Ian MacMillan; Eugen Teszler; Dairo Moody
Cc: Cathy Ragland; Rodolfo Chacon
Subject: APCI Rule 1118 Amendment Comments - 2nd Proposed Language Version

Ian,

Appreciate the time you and your staff spent with me following the working group meeting on Tuesday to discuss a few comments/concerns we had. Just wanted to provide in writing as well as add any additional information that has been reviewed/discussed internally as well as with refinery inspection team (Cathy and Rudy cc'd):

- **(c)(13)(C)(ii) –** This section is written as if a process already exists whereby recovered flare gas is utilized as fuel gas for a process unit. Recovery of flare gases does not occur at our facilities so if the intent is otherwise we would ask that this be reworded or clarified with our facilities in mind. If no changes, it should be expected that we would indicate this section as 'non-applicable by design' in our submitted scoping documents. 4-1
- **(i)(4) –** We initially raised concern that we have daily flows at both plants that exceed 100,000 SCF and that notifications would need to be submitted every day creating a nuisance (and likely defeating the purpose/intent of this condition). After further review internally and discussion with District refinery inspection staff, it was determined that only Carson plant exceeded 100,000 SCF on a daily basis and further investigation identified a compressor leak that was able to be immediately resolved which eliminated basically all flow to flare with the exception of (by design) N2 purge flows of approximately 2,500 SCFH. It was further discussed that a team including APCI, rules, engineering/permitting and/or compliance should probably meet in the near future to come to an official/unofficial agreement on methodology/approach to backing out N2 purge flow from our flare flow monitoring measurement (at both facilities) instead of treating it as a combustible flare stream w/ associated emissions which is the current practice. We have no further issues with this condition as written. 4-2
- **Attachment B –** We wanted to just clarify that under the proposed regulation our facilities are not required to install and certify monitors that can measure net heating value (NHV). As such, our expectation is that we would continue to utilize existing ROG and CO emission factors that rely on HHV values once amendment adopted and continuing beyond January 30, 2019. We would want to know ASAP if this understanding is incorrect and discuss. 4-3

Thanks and if you need to discuss anything tomorrow I am available.

Jim Reebel
Principal Environmental Engineer **Air Products and Chemicals, Inc.** Los Angeles Area
Mobile: (714) 642-4252, Office: (310) 847-7300 x13, Fax: (310) 847-7311
Email: reebeljc@airproducts.com

Response 4-1
The Scoping Document requirements in (c)(13) are designed to analyze the feasibility of making improvements to facilities to reduce flaring emissions. Clause (c)(13)(C)(ii) refers to an analysis of the sudden loss of a fuel gas consumer. For facilities that do not currently recover flare gases into their flare gas system, the Scoping Document could result in an analysis of adding a fuel gas consumer for other clauses [e.g., adding a cogeneration unit for (c)(13)(C)(i), (iii), or (iv)]. In this case, the response to (c)(13)(C)(ii) should include an analysis of what would occur with the sudden loss of this fuel gas consumer. If no fuel gas consumer is ever considered as a part of a facility's design, a response of 'non-applicable by design' would be acceptable.

Response 4-2
No changes have been made to (i)(4) in response to this comment. Staff appreciates that the facility has pro-actively taken steps to reduce the release of vent gas.

Response 4-3
Air Products as part of its permit is required to annually test its vent gases for high heating value content, and then utilize this value to calculate their emissions. The updated emission factors in Attachment B will require the facility to now use the net heating value instead of the high heating value, where appropriate.

Dairo Moody
Eugene Teszler
SCAQMD
21865 Copley Drive
Diamond Bar, CA 91765

COMMUNITIES FOR A BETTER ENVIRONMENT

Re: Summary Comments Flare Rule 1118 – detailed comments to be submitted later

Dear AQMD Staffmembers,

In addition to comments submitted orally at previous workgroup meetings, included below are a summary of key CBE comments on Rule 1118. We will also be submitting more detailed comments in writing. We provide this summary now because we understand you are considering the next version of your staff report and making changes to the proposed Rule 1118.

As flaring can cause major emissions and high pollutant concentrations in a short time frame and are indicators of stability of refinery operation, they are cause for careful scrutiny. Flaring is of great concern to CBE and our members who are impacted by multiple refineries in the South Coast (and Bay Area). 5-1

We appreciate the District's hard work to improve this rule! We especially appreciate the District's plan to evaluate measures to minimize or eliminate planned flaring, to carry out optical remote sensing of flare emissions, and additional improvements. **We also strongly support the District requiring fees for VOCs as well as SOx emissions, and we will be submitting comments about this subject.**

Here are some remaining key loopholes that need to be removed:

- **Flare Minimization Plans are required for all refineries in the Bay Area Air Quality Management District,[1] have been for over a decade, & should be added as a requirement in the South Coast** for all covered facilities (refineries as well as Air Products & Air Liquide flares). Right now, only facilities exceeding a certain threshold are required to submit them. This leaves out a major pollution prevention tool, and waits until after-the-fact to put it in place. We have been asking for this provision since the first rule adoption proceedings over ten years ago. Requiring Flare Minimization Plans across the board would allow the District to compare the plans of each refinery, and identify best practices and comparative deficiencies. Such plans should not be considered burdensome paperwork, but important pollution prevention and safety 5-2

[1] Bay Area Air Quality Management District requires Flare Minimization Plans for all refineries: *"12-12-401 Flare Minimization Plan Requirements: The owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit to the APCO a FMP [Flare Minimization Plan] in accordance with the schedule in Section 12-12-402."* Available at: http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/reg-12/rg1212.pdf

plans. EPA's recent determination that flare VOC Emissions Factors were underestimated by at least 10 times, is one more reason to ensure that each facility has a robust, well documented plan to minimize ALL flaring. 5-2 cont'd

- **"Clean Service" flaring emissions and other flares burning propane, butane, and methane have low-balled Emissions Factors in the rule.** The ROG or VOC[2] emissions for "Clean Service" flares and other flaring of propane, butane, and methane (natural gas) are set at extremely low Emissions Factors. For example for propane and butane, an Emissions Factor is set at of 0.003 lbs/MMBTU[3] (compared to the 0.66 lbs/MMBTU for other hydrocarbons, which is 220 times higher). ROG emissions from all hydrocarbons should be increased to use a factor of at least 0.66 lbs/MMBTU factor currently set in the rule for vent gases in general. Even the 0.66 lbs/MMBTU emissions factor is identified in AP-42 as only applying to extremely efficient flaring under favorable conditions of gas content and flow velocity. It is well established that flare efficiency can become quite low under many conditions that are common, causing emissions to multiply to high levels. CBE routinely receives complaints from community members about flaring that the District has called "Clean Service" flaring. CBE previously submitted evidence on multiple studies regarding degraded combustion efficiency measured at oil refinery flares, and we will provide updated comments on this subject in our detailed upcoming letter. 5-3
- **Inspections should be made by the District to eliminate by-pass pipes that avoid flare monitoring equipment, such as those found at the Torrance refinery are present.** The same problem was found at the Chevron Richmond refinery in the past, indicating that California refineries require additional inspections. 5-4
- **"Essential Operational Needs" is too generalized a category, is not given special consideration in the Bay Area rule, and should be struck in the South Coast rule**: Currently the rule states a requirement to *"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."* The Bay Area regulation includes no such allowance. 5-5
- **Specific Cause Analysis language has a new exemption** for non-standard operation during planned events, which should not be added to the rule.[4] 5-6

[2] Reactive Organic Gases, or Volatile Organic Compounds

[3] Draft AQMD Rule 1118 updates, Attachment B, GUIDELINES FOR CALCULATING FLARE EMISSIONS, Propane and Butane, p. 36.

[4] Rule 1118 states: *"Specific Cause Analysis is a process used by a facility subject to this rule to investigate the cause of a flare event, identify corrective measures and prevent recurrence of a similar event."* and *"Conduct a Specific Cause Analysis for any flare event, excluding planned shutdown, planned startup and turnarounds, and for any flare event resulting from non-standard operating procedure during a planned shutdown, planned startup or turnaround, when either: (A) Emissions exceed 100 pounds of VOC; or (B) Emissions exceed 500 pounds of sulfur dioxide; or (C) More than 500,000 standard cubic feet of vent gas are combusted"*

- **Performance Targets now include a weakening amendment – previously the rule required minimizing all emissions including VOCs, SO2, and other emissions, but now only requires minimizing SO2 in this section:** *"The owner or operator of a petroleum refinery subject to this rule shall ~~minimize flare emissions~~ . . ."* This has been replaced with language further in the text to minimize only sulfur dioxide emissions. It is very important that the requirement to minimize all flaring emissions be reinstated. 5-7
- **Furthermore, the District had previously been evaluating tightening the SO2 Performance Standard to 2.5 tons/million barrels** of crude processing capacity, but currently the draft still allows 0.5 tons/million bbls. In fact, some refineries have met tighter standards at 0.1 tons/million barrels, and the District should set the standard to reflect Best Practices, not average practices. 5-8
- **Very important process description to be submitted to the District in Flare Minimization Plans has been removed.** (These are requirements that detailed process flow diagrams of all upstream equipment and process units venting to each flare be identified in the Flare Minimization Plan that were previously Section (c)(1)(B).) 5-9

Thanks again for all your work on this important regulation. Julia

May
Senior Scientist
Communities for a Better Environment (CBE)

Response 5-1
Thank you for your comment. Responses 5-2 through 5-9 contain specific responses.

Response 5-2
Staff agrees that additional analysis is required by facilities to further reduce their flaring emissions. The Flare Minimization Plan (FMP) requested in this comment is different than the current requirements for a FMP in Rule 1118. FMPs required by Rule 1118 and PAR 1118 investigate why an annual Performance Target was exceeded, and evaluate how to avoid this exceedance in the future. The requested FMP appears to be more of a forward-looking analysis that evaluates all potential causes of flaring, not just what may have caused an exceedance historically. Instead of changing the FMP definition and requirements in PAR 1118, there are two separate mechanisms, which should address this comment.

First, the EPA Refinery Sector Rule already requires facilities to undergo a similar process as requested in this comment. In the RSR, requires facilities to *"Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases."* [40 CFR Part 63, Subpart CC § 63.670 (o)(1)]. The RSR also states *"The owner or operator must develop and implement the flare management plan no later than January 30, 2019 or at startup for a new flare that commenced construction on or after February 1, 2016."* and *"The owner or operator must comply with the plan as submitted by the date specified in paragraph (o)(2)(i) of this section. 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. The owner or operator must comply with the updated plan as submitted."* [40 CFR Part 63, Subpart CC § 63.670 (o)(2)(i) and (ii)]

Second, as Part of PAR 1118, facilities must evaluate even more stringent standards as part of a detailed engineering analysis in the Scoping Documents required in (c)(13). As part of the Board Resolution that will be considered by the Board with the adoption of PAR 1118, a resolution will be added directing staff to undertake a second phase of rulemaking to further reduce flaring that will consider the information returned in Scoping Documents. These Scoping Documents will include site-specific feasibility analyses of additional controls that are not currently required by any rules from BAAQMD, SCAQMD, or EPA.

Response 5-3
The flaring emission factors for butane and propane in Attachment B have been updated in response to this comment and are now consistent with recent updates to EPA's AP-42 Chapter 1.5. The emission factors in Attachment B in the existing Rule 1118 are based on an older version of AP-42 Chapter 1.5, which has since been updated since the last rule amendment. With regards to combustion efficiency, there are many parts of the EPA Refinery Sector Rule designed to improve combustion efficiency, and they have been included in PAR 1118, including limits on flare tip velocity [(c)(3)], net heating value in the combustion zone [(c)(4)], and new prohibitions on smoking flaring events [(c)(10)]. In addition, the proposed pilot study of optical remote sensing could lead to new techniques that can better evaluate flaring emissions, and can potentially improve flare combustion efficiency by providing real-time feedback on combustion dynamics to facility operators.

Response 5-4
In addition to regular facility inspections, SCAQMD Compliance staff have inspected every facility subject to Rule 1118 specifically to determine if there are any bypass lines that send vent gas to the flare tip that are not monitored. No bypass lines have been identified as part of these inspections.

Response 5-5
The definition of Essential Operational Needs has been narrowed to remove emergency flaring and minor venting that should be recovered by existing flare gas recovery systems. As noted by the commenter, BAAQMD Rule 12-12 does not specifically call out flaring under the term Essential Operation Need. However, every facility must submit a Flare Minimization Plan (different than a FMP required by SCAQMD Rule 1118) that details the steps a facility has taken and will take to minimize flaring, including from activity that is contained within the Essential Operational Need definition in Rule 1118. For example, under BAAQMD Rule 12-12, FMPs must evaluate the expeditious implementation of feasible prevention measures, and shall include an audit of *"the scrubbing capacity available for vent gases including any limitations associated with scrubbing vent gases for use as a fuel; and shall consider the feasibility of reducing flaring through the recovery, treatment and use of the gas or other means."* However, this requirement does not prohibit the flaring of gases that are incompatible with the fuel gas system if it is infeasible to provide sufficient scrubbing or storage capacity for all vent gases. The requirements in BAAQMD Rule 12-12 are therefore no more stringent than SCAQMD Rule 1118 with regards to Essential Operational Needs.

Response 5-6
Paragraph (c)(6) has been modified to make it clear that the described exemption does not apply.

Response 5-7
The phrase *"minimize flare emissions"* has been added back into subdivision (d). There are no amendments in PAR 1118 that change the purpose of the rule to *"control and minimize flaring and flare related emissions."*

Response 5-8
Before the Performance Targets can be lowered, a feasibility analysis must be conducted. The Scoping Documents proposed in (c)(13) will provide site-specific analyses conducted by facilities to evaluate what can be implemented to further reduce flaring emissions.

Response 5-9
The requirement for a detailed process flow diagram is now in the Scoping Documents in (c)(13)(D) and also in Flare Monitoring and Recording Plans in (f)(4)(E).

COMMUNITIES FOR A BETTER ENVIRONMENT

Via Electronic Mail

May 19, 2017

Dairo Moody
Eugene Teszler
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Proposed Amended Rule 1118

Dear SCAQMD Staff Members:

Thank you for your work on Proposed Amended Rule 1118. We submit these comments on behalf of Communities for a Better Environment ("CBE"), an environmental justice organizations that advocates on behalf of residents in Wilmington, a neighborhood cumulatively impacted by five oil refineries. This community is also impacted by the ports of Los Angeles and Long beach, the I-710 and I-110 freeways, heavy diesel truck traffic for goods movement through this corridor, and is home to the largest urban oil field in the United States. Wilmington currently ranks in the top 5% of communities with the highest pollution exposure and social vulnerability in the state.[1] These communities cannot bear more emissions of toxic air contaminants or criteria pollutants, and must be protected.

We commend the Air District for updating Rule 1118, and for taking steps to tighten regulation of flares at refineries, including by removing the $4 million cap on mitigation fees for violation of the performance standard for SOx emissions. Julia May, senior scientist at CBE, submitted written comments regarding Proposed Amended Rule 1118, and we also submitted oral comments during public working group meetings. This letter supplements comments already submitted, and provides further analysis regarding our proposed recommendations to tighten the performance standard for SOx emissions, and to establish a performance standard for VOCs. 6-1

The Air District may impose stricter performance standards pursuant to its police powers as a governing agency. The Air District is the air pollution control agency for the South Coast Basin, and has the authority to set air quality standards and impose fines for violations of these standards. In 2005, the Air District established a performance standard for emissions of SOx 6-2

[1] Ofc. of Envt'l Health Hazard Assessment (2014) *CalEnviroScreen Version3.0*, https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30.

from refineries, and imposed increasingly onerous fines depending upon the level of exceedance of the applicable performance target.[2] As documented in the Air District's May 11, 2017 Public Workshop, fines for violation of the SOx performance target were not imposed on all refineries, but were imposed only on refineries that violated the SOx performance standard.[3]

Penalties imposed by the Air District for violation of the SOx performance standards described in Rule 1118 do not constitute a "tax." **There is no justification in law for such a proposition.** The California Constitution provides that "[a]ny change in state statute which results in any taxpayer paying a higher tax must be imposed by an act passed by not less than two-thirds of all members elected to each of the two houses of the Legislature[.]"[4] However, "[a] fine, penalty, or other monetary charge imposed by . . . the State, as a result of a violation of law" is excepted from and not included within the definition of "tax."[5]

Mitigation fees assessed on refineries that violate the SOx performance standard are a penalty, because they are imposed only after a violation has occurred with the purpose of deterring law breaking activity. "A penalty . . . regulates conduct . . . by deterring those tempted not to [comply with the law.]"[6] In *Franchise Tax Board*, the Court of Appeals distinguished taxes from penalties by reasoning that "while a tax raises revenue if it is obeyed, a penalty raises revenue only if some legal obligation is disobeyed[.]"[7] 6-2 cont'd

Taken to its logical conclusion, the argument that regulatory fines imposed by the Air District for violating air quality standards constitutes a tax, would eviscerate the Air District's authority to promulgate regulations to control regional air pollution. Under such a scheme, any air quality standards amended, or newly promulgated after 2011, would require approval by two-thirds of the Legislature. Such a broad prohibition of the Air District's regulatory authority was not contemplated by the passage of Proposition 26, and is not otherwise supported by law. Thus, under the plain language of the Constitution, penalties imposed by the Air District for violation of the SOx performance standard for refinery flares are not "taxes." [8] The Air District has plain authority to amend Rule 1118 and tighten the SOx performance standard, and also to impose a new performance standard for VOCs.

The Air District should tighten the performance standard for SOx to 0.1 tons per million barrels, while it considers even tighter standards down to 0.0 tons. CBE strongly recommends tightening the performance standard for SOx emissions, to 0.1 tons per million barrels of crude processing capacity. Refineries have met lower emissions levels of 0.1 tons of 6-3

[2] S. Coast Air Quality Mgmt. Dist. (2005) Rule 1118, subd. (d).
[3] S. Coast Air Quality Mgmt. Dist. (May 11, 2017) *Public Workshop: Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares*, at 13.
[4] Cal. Const. Art. 13A, § 3(a).
[5] *Id.* at § 3(b).
[6] *Cal. Taxpayers' Ass'n v. Franchise Tax Bd.* (2010) 190 Cal.App.4th 1139, 1148.
[7] *Id.* at 1148–49.
[8] *See People v Superior Court (Zamudio)* (2000) 23 Cal.4th 183, 192 ("If there is no ambiguity in the language of the statute, . . . the plain meaning of the language governs[.]") (internal citations and quotation marks omitted).

SOx/million barrels, and the District should set the SOx performance standard at this level to reflect *best* industry practices, not average industry practices. The Air District itself considered tightening the standard down to 0.25 tons per million barrels early in the current rulemaking update. 6-3 cont'd

The Air District should create a performance standard for VOCs. Actual emissions of VOCs exceeded reported emissions by over 6 times.[9] Excess emissions of VOCs from oil refineries is a serious and underreported problem, and the Air District should develop a performance standard for VOCs to lower these emissions. This problem is also consistent with EPA's finding that the current flare VOC emission factor should be ten times higher. As the South Coast is an extreme non-attainment zone, it is all the more important to use such available means to cut VOCs. 6-4

A performance standard is a successful regulatory successfully at reducing flaring. The slides presented in the Air District's first public workshop make a compelling case for establishing a performance standard for VOCs. During that presentation, the Air District documented that most facilities make the effort to reduce emissions below the SOx performance standard to avoid paying onerous penalties. S. Coast Air Quality Mgmt. Dist. (Feb. 28, 2017) *First Working Group: Proposed Amended Rule 1118*, at 19, 21. The Air District should replicate this successful regulatory approach, and establish a performance standard for flaring VOCs to deter refineries from excess VOC flaring. 6-5

Thank you for your work on Proposed Amended Rule 1118. The communities living near refineries in the South Coast Air Basin are paying the costs of excess SOx and VOC emissions with their health, and in some cases with their lives. We urge you to adopt a tighter performance standard for SOx and a strict performance standard for VOC emissions to protect these communities.

Respectfully submitted,

/s/

Jaimini Parekh
Attorney/ VABANC Law Foundation Fellow

Gladys Limón (ext. 117)
Staff Attorney

[9] FluxSense (Apr. 11, 2017) *Emission Measurements of VOCs, NO2, and SO2 from the Refineries in the South Coast Air Basin Using Solar Occultation Flux and Other Optical Remote Sensing Methods*, at 4.

COMMUNITIES FOR A BETTER ENVIRONMENT
6325 Pacific Blvd Suite 300 · Huntington Park, CA 90255 · P: (323) 826-9771 // F: (323) 588-7079
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Response 6-1

Thank you for the comments. Specific responses are included in Responses 6-1 through 6-5 below.

Response 6-2

This comment states that the District has the authority to impose tighter SOx Performance Targets and to also impose a new Performance Target for VOCs, because the Mitigation Fees paid by the facilities when the SOx targets are exceeded are fines paid to settle a penalty and not taxes. However, these Mitigation Fees paid by facilities are neither taxes nor fines, they are instead an option that facilities can use to stay in compliance with the rule. The Mitigation Fees paid by facilities pursuant to Rule 1118 are not a result of a violation as the fees are an explicit compliance option allowed under the rule. Facilities could opt out of the fees by taking steps to keep their emissions levels lower than the Performance Target. In other words, reduction in emissions or payment of mitigation fees are each compliance options.

Further, because tightening the current SOx Performance Target or adding a new VOC Performance Target would significantly affect air quality or emissions limitations the District must first analyze the socioeconomic impacts of this change (Health and Safety Code §§ 40440.8, 40728.5, 40920.6). In addition, the new controls that may be required with tighter Performance Targets could require an extensive CEQA analysis, including an analysis of alternatives. Because of the extensive analyses that must be conducted before tightening the Performance Targets, including a full socioeconomic assessment, potential analysis under Proposition 26 for proposed fees, and a CEQA analysis, staff has proposed a two-phase rulemaking approach. Among other updates, the first phase requires facilities to conduct site-specific feasibility assessments with Scoping Documents. The second phase of rulemaking will then evaluate potential changes to the Performance Targets using the feasibility assessments within the submitted Scoping Document.

Response 6-3

As discussed in Response 6-2, any potential changes to the Performance Targets requires a feasibility and socioeconomic analysis. Staff has not proposed a lower Performance Target of 0.25 SOx tons per million barrels as part of this first phase of rulemaking, which commenced in October 2016. All facilities will be evaluated in the second phase of rulemaking to determine if there are best practices from lower emitting facilities that can be feasibly applied to other facilities.

Response 6-4

The comment states that VOCs are under-reported from refineries generally, and from flares specifically. The facility-wide under-reporting of VOCs from refineries was a conclusion of a SCAQMD-funded study conducted by FluxSense Inc. This study used a variety of different Optical Remote Sensing (ORS) techniques to evaluate facility-wide emissions from local refineries. While the results of this study are important, and point to further work that is needed to evaluate emissions from refineries, the monitoring techniques used have not yet been found to be appropriate for developing facility-wide emission inventories. SCAQMD staff plans to continue encouraging the development of the technologies evaluated in this study, including for specific applications such as leak detection or stack-specific monitoring. For example, staff is proposing an ORS pilot study to evaluate the potential for using these technologies specifically for flare monitoring. EPA relied on similar ORS studies to revise its stack-specific flaring emission factor guidance in AP-42. PAR 1118 is updating its emission factors based on this updated EPA guidance.

Response 6-5

As stated in Response 6-2, a feasibility and socioeconomic analysis is required before the Performance Targets can be tightened. This analysis will be conducted in a second phase of rulemaking.

Entire e-mail chain is one comment.
7-1

From: Julia May
Sent: Friday, June 2, 2017 4:52 PM
To: Dairo Moody; Ian MacMillan
Subject: P.S: re 0.003lb/MMBTU flare EF came from, but I still question 0.009

Ok - Now I see that the new AP 42 External Boilers burning Propane has an EF for TOC of 1 lb/1000gals, which is roughly 3 times the old EF of 0.3lbs/1000 gals (which = .003 lbs/MMBTU from my corrected calcs below), so I see why you ended up with a new EF of .009lbs/MMBTU.

However, this still doesn't really reconcile well with other HC's having a new EF of 0.66lbs/MMBTU - drastically higher.

I think propane, butane, methane are getting off the hook with major emissions underestimations, and I'm very concerned about so called "Clean Service" flares continuing to get these breaks. Community members are also very concerned about these flares. They complain to us when they see these flaring.

On Fri, Jun 2, 2017 at 3:57 PM, Julia May wrote:

> Just saw a silly error a while back that I made in sending the email in the chain below too quickly to you guys, while I was on the phone at the same time. See correction below.
>
> **This may explain where the propane emission factor of .003lbs/MMBTU came from,** that you had in the rule. When I correct my calculation in the chain (divided by, not times!) you get 0.003lbs/MMBTU.
>
> **CORRECTING (**using the 0.3 lbs/thousand gals from San Diego APCD in link below, which came from the ROG EF from AP42 Boilers burning Propane, and 91,600 btu/gal for propane):
>
> 0.30 lbs/1000 gals / (91,600 BTU/gal propane x 1000/1000) =
>
> 0.30 lbs/1000 gals / (91.6MMBTU/1000 gal) = ,**003 lbs/MMBTU**
>
> However, regardless of where the factor came from, I do not believe that such a low number is correct, when other hydrocarbons are now found to be at 0.66lb/MMBTU. **Further, I didn't see where you got the new number of 0.009 lbs/MMBTU new EF that you inserted into the flare rule. That still seems to be an unreasonably low EF compared to other hydrocarbons.**
>
> **CAN YOU SEND POINT ME TO EXACTLY WHAT YOU ARE USING TO GET 0.009LBS/MMBTU?**
>
> Thanks much, Julia May, CBE

On Fri, May 12, 2017 at 9:23 AM, Julia May wrote:

For our discussion this morning, I wanted to bring up the Emission Factor for propane *(and same principles apply to butane, probably methane).* For example – the following is an Emission Factor for ROG that I just grabbed from the San Diego site for uncontrolled boilers burning propane, which comes from AP-42 - 0.30 lbs/1000 gals. (The South Coast probably has a similar one.)

http://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Misc/EFT/Liquid_Combustion/APCD_Boiler_P ropane_Fired_10-100_MMBTU_Uncontrolled.pdf

CONVERTING FROM 1000 GALS TO MMBTU GIVES THE FOLLOWING:

0.30 lbs/1000 gals* x (91,600 BTU/gal x 1000/1000) =

0.30 lbs/1000 gals x 91.6MMBTU/1000 gal = **~27** lbs/MMBTU

While there are likely different EFs available, the above numbers are a far cry from the **0.003lbs/MMBTU** value in Rule 1118. Do you see anything wrong with this analysis? This indicates to me that the propane & butane EFs also need to be corrected (not just the general vent gas EF).

Response 7-1

This comment states that the ROG emission factor in Rule 1118 is too low for propane and butane and a higher value should be used since the vent gas emission factor is so much higher. Because more specific information is not currently available, the emission factors within PAR 1118 and the existing Rule 1118 rely on EPA's AP-42 guidance document. The proposed updates within PAR 1118 are consistent with updates to AP-42 since the last amendments to Rule 1118 in 2005. The ROG emission factor will be increased about three-fold for propane and butane, and about ten-fold for general vent gas. Recognizing the limitations of the use of emission factors, staff is proposing to conduct an Optical Remote Sensing pilot study to determine if direct monitoring of flaring emissions with emerging technologies is possible. This study will be designed to evaluate clean service flares as well as general service flares. Further, the Scoping Documents that facilities are required to prepare must now evaluate the feasibility of achieving a new VOC emissions limit of 0.1 tons per year from clean service flares. The second phase of rulemaking on 1118 will consider the findings from the Scoping Documents to determine what additional steps can be taken to further reduce flaring emissions, including from clean service flares.

From: Julia May [julia@cbecal.org]
Sent: Monday, June 05, 2017 4:08 PM
To: Ian MacMillan; Dairo Moody; Eugen Teszler
Cc: Jaimini Parekh
Subject: Rule 1118 Comment: AP-42 Flares Ch. higher TOC EF for burning propane/propylene

E-mail is one comment.
8-1

Good afternoon -- I will be sending a more formal comment letter in addition to our earlier Flare Comments, but **I wanted to repeat an important issue before you finalize your packet, on one particular concern of ours -- that pollutants such as propane would continue to have <u>very low EFs</u> (Emission Factors) in the most recent version of the rule, and this should be changed.** Although you have changed the ROG EF for Propane from 0.003lbs/MMBTU to up to 0.009, this is still orders of magnitude lower than the EF for other HCs (0.66)

You got the 0.009 lb/MMBTU I believe from converting the EF for external combustion industrial boilers, which is equivalent to the published 1 lb/1000 gallons EF. I sent corrected calculations last week showing the conversion to lbs/MMBTU. (I corrected earlier calculations which had an error.)

However, this Boiler EF has a rating of "E", which means Poor.

On the other hand, EPA set an EF in updated AP42 specifically for flaring a combination of propylene and propane, resulting in Total HCs emitting at 0.14 lbs/MMBTU for Total HCs. (p. 13.5-5) **This factor is given a B rating (Above Average).**
https://www3.epa.gov/ttn/chief/ap42/ch13/final/C13S05_12-13-16.pdf

I propose you at a minimum use the 0.14 lbs/MMBTU, or don't differentiate propane at all, and use the 0.66 lbs/MMBTU factor for all HCs. Even the 0.66lbs/MMBTU factor is not conservative – I noticed that the EPA technical basis document for the new flare emissions factor showed that emissions can go much higher (up to 1.6 lbs/ MMBTU in their flare testing). Furthermore, they had previously thrown out any data where the efficiency went below 98%. If you continue to include the extremely low EF in Rule 1118 for so called "Clean Service" flares, this will low-ball and hide true impacts, without a good basis to do so. This is especially problematic when updated EPA investigations found that flares have far higher emissions than previously acknowledged.

The AP42 Flare Chapter 13.5 EF of 0.14 lb/MMBTU is at least in the ballpark of the EF for other HCs (0.66lbs/MMBTU), which seems much more reasonable than the extremely low factor of 0.009. I don't see why propane flaring should result in such drastically lower emissions compared to other HCs.

I would appreciate a response on this issue, and also want to thank you again for all your hard work on this regulation.

Julia May
Senior Scientist
Communities for a Better Environment (CBE)

Response 8-1

See Responses 5-3 and 7-1. The proposed emission factor from chapter 13.5 of AP-42 in this comment is not appropriate for use for propane and butane flaring. The emission factor cited is from a combination of 80% polypropylene and only 20% propane, whereas clean service streams include streams of 100% propane or 100% butane. Recognizing that more information is needed on flaring emissions, staff is proposing an Optical Remote Sensing pilot study to determine in emerging technologies can provide more information based on observations of flare plumes.

Torrance
Refining Company

Torrance Refining
Company LLC
3700 W 190' Street
Torrance, CA 90504
www.pbfenergy.com

June 2, 2017 Via e-mail at: IMacMillan@aqmd.gov

Mr. Ian MacMillan
Planning and Rules Manager
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on Proposed Amended Rule 1118, Control of Emissions from Refinery Flares

Dear Mr. MacMillan:

Torrance Refining Company LLC ("TORC") appreciates the opportunity to provide comments on the South Coast Air Quality Management District's ("SCAQMD's") July 2017 Proposed Amended Rule 1118, Control of Emissions from Refinery Flares ("PAR 1118"). TORC adopts and incorporates by reference herein the comments of the Western States Petroleum Association ("WSPA") on PAR 1118.

Please note that in submitting this letter, TORC reserves the right to supplement its or WSPA's comments as it deems necessary, especially if additional or different information is made available to the public regarding PAR 1118. 9-1

We commend the SCAQMD for working closely with the regulated community and other stakeholders to incorporate many needed revisions to PAR 1118 over the past months. However, we believe that the recent comments from WSPA additional revisions to PAR 1118 are warranted in order to ensure an effective, technically feasible, and cost effective rulemaking. We look forward to continuing to work collaboratively with the SCAQMD to arrive at rulemaking that accomplishes the previously stated goals and that minimize flaring emissions without compromising process safety.

Sincerely,

David L. Ingram
Manager – Health, Safety, and Environmental

cc: Steve Steach
Darren W. Stroud
Penny Wirsing
Craig Sakamoto

Response 9-1
Thank you for your comments. This comment expresses support for a comment letter from WSPA. Responses can be found in Responses 10-1 through 10-17.

From: Patty Senecal <psenecal@wspa.org>
Date: Wednesday, May 10, 2017 at 9:10 PM
To: Wayne Nastri <wnastri@aqmd.gov>
Cc: Cathy Reheis-Boyd <creheis@wspa.org>
Subject: PAR 1118 (Refinery Flares) Wayne,

WSPA believes this rule is not ready to go to Stationary Source next week or to the Governing Board in July. This is a very technical rule and Staff is trying to include the USEPA Refinery Sector Rule requirements (and as currently written, some of the requirements, calculations, and technology for measurement conflict). There are a lot of technical concerns we all need to continue to work out and the short amount of time from the release of the draft language & draft preliminary report (April 21) until Board adoption (July 7) is problematic . We believe this rule is being unduly rushed, given that less than three weeks will have elapsed from the release of draft language to the public workshop tomorrow (May 11). Many of the refineries are making updates to their flare systems to bring them into compliance with USEPA Refinery Sector Rules, and with the short time frame of the District's rule, they are now having to consider making changes to comply with 3 regulations at the same time- the old R1118, PAR 1118, and USEPA RSR.

WSPA had a productive meeting with your staff yesterday, (5/10), but we weren't able to get through all our issues with the proposed language; we will schedule another meeting. This is also a two-part rulemaking, so having conflicts remain going into the second part of the rulemaking will only cause further confusion and issues if not thoughtfully addressed now. 10-1

WSPA is asking for your consideration to move this rule forward on the rule forecast to the October Board meeting and not to take this to Stationary Source on May 19. Thank you for your consideration.

Current schedule:

Feb 28	First working group meeting
March 3 & 27	Public meetings (Torrance & Wilmington)
April 19	Bridget and I had an initial meeting with Phil Fine and Ian MacMillan regarding the rule
April 21	Draft Rule Language and Draft Preliminary Report released
May 10	WSPA & members meet with District to present technical issues (productive meeting)
May 11	Public Work Shop & CEQA Scoping meeting (WSPA will make comment to slow down the process)
May 19	District has scheduled to present to Stationary Source Committee
July 7	Board adoption

Patty Senecal
Director
Western States Petroleum Association
(310) 678-7782
patty@wspa.org

Response 10-1

This comment asked for more time to develop PAR 1118 as there are many technical issues to consider with the EPA Refinery Sector Rule. Staff has continued to meet with individual refineries and WSPA since this comment has been received, and has made many changes to the rule that staff believes has resolved most of these technical issues. Responses to a subsequent comment letter from WSPA, which does not request more time for rule development, are contained in Responses 11-1 through 11-17.

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Bridget McCann
Manager, Southern California Region

June 2, 2017

Mr. Ian MacMillan
Planning and Rules Manager
South Coast Air Quality Management District 21865
Copley Drive
Diamond Bar, CA 91765

Via e-mail at: IMacMillan@aqmd.gov

Re: **Comments on Proposed Amended Rule 1118, Control of Emissions from Refinery Flares**

Dear Mr. MacMillan:

Western States Petroleum Association (WSPA) appreciates this opportunity to provide comments on Proposed Amended Rule (PAR) 1118, Control of Emissions from Refinery Flares. WSPA is a non-profit trade association representing companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in five western states including California. WSPA-member companies operate petroleum refineries in the South Coast Air Basin that are affected by Rule 1118.

The purpose 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. The provisions of the rule are not intended to pre-empt any operations and practices with regard to safety.[1] The stated objectives for the proposed amendments included: (a) updating Rule 1118 emissions factors to reflect recent revisions to the U.S. Environmental Protection Agency's (EPA) AP-42 emission factors; (b) harmonizing Rule 1118 with the recently promulgated U.S. EPA Refinery Sector Rule (RSR) requirements for refinery flares; and (c) updating the emissions fees.[2] 11-1

The proposed rulemaking schedule for PAR 1118 has been incredibly aggressive, especially given the complexity of the facilities covered under the rule and the highly technical nature of the applicable requirements. Given that accelerated schedule, WSPA appreciates the District Staff's willingness to meet and work with WSPA, its members, and the other stakeholders, despite considerable time constraints.

WSPA and its members have reviewed the revised version of PAR 1118.[3] Numerous changes have been made by Staff in response to comments from the stakeholders. However, there remain a number of important areas in the draft language where improvements are needed to clarify the applicable requirements and, importantly, minimize conflicts with the EPA RSR regulation. These are presented below.

[1] South Coast AQMD Rule 1118, Section (a).
[2] South Coast AQMD, Presentation to First Working Group, PAR 1118, Control of Emissions from Refinery Flares, February

28, 2017.

[3] South Coast AQMD PAR 1118, Version 5/26/17.

Section (b), Definitions

1. Section (b)(3)(B), Essential Operational Need

The draft rule should be revised to maintain inclusion of "relief valve leakage" within the definition of Essential Operational Need (EON). Relief valves are configured to vent into flare gas headers when there is malfunction or intermittent minor venting from equipment or systems (e.g., sampling systems, pumps, compressors, etc.). In most cases, this venting is handled by flare gas recovery systems. However, the current draft language would create a conflict if such leakage happened to be occurring into the flare header during a flare event. It is most appropriate to maintain this activity within the EON definition. In the alternative, the relief valve leakage could be included under the definition of "Emergency" found in Section (b)(2). 11-2

Proposed Change

(b)(3)(B) ~~Relief valve leakage due to malfunction~~; Relief valve leakage due to malfunction;

2. Section (b)(3)(E), Essential Operational Need

Similarly, the draft rule should be revised to maintain inclusion of "intermittent minor venting" within the definition of Essential Operational Need (EON). Intermittent minor venting includes venting from sight glasses, compressor bottles, sampling systems or pump/compressor seals. These are vented to the flare headers and captured by the flare gas recovery system. However, the current draft language would create a conflict if such leakage was occurring into the flare header at the same time as a flare event. It would be most appropriate to maintain this activity within the EON definition. Alternatively, the District could add a de minimis flow exemption for intermittent minor venting instead of removing it. 11-3

Proposed Change

(b)(3)~~(E) Intermittent minor venting from:~~ (E) Intermittent minor venting from:

(i) ~~Sight glasses~~; Sight glasses;

(ii) ~~Compressor bottles;~~ Compressor bottles;

(iii) ~~Sampling systems; or~~ Sampling systems; or

(iv) ~~Pump or compressor systems;~~ Pump or compressor systems;

3. Section (b)(5), Flare Event

Under the current draft language, the definition of "Flare Event" would be revised to consider multiple flare events that can be attributed to the same process unit(s) or equipment and have more than one start and end within a 24 hour period as a single event (i.e., not separate or unique events). This would represent a significant change to the rule when considered together with per event requirements in the rule. WSPA recommends that this new language be removed from the Flare Event definition.

Proposed Change

(b)(5) FLARE EVENT is any intentional or unintentional combustion of vent gas in a flare. ~~The flare event ends when the flow velocity drops below 0.12 feet per second,~~ 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. 11-4

Section (c), Requirements

1. **Section (c)(3), Flare Tip Velocity Limits**

This section should be revised to directly incorporate applicable EPA RSR requirements for flare tip velocity. The current draft language would require flares at petroleum refineries to operate such that the flare tip velocity (averaged over 15 minutes) is less than 60 feet per second, or the lesser of 400 feet per second or Vmax. While this appears similar to the RSR requirements, it is not the same requirement.

The EPA RSR regulation's flare tip velocity standard is applicable when regulated material is routed to the flare for at least 15 minutes and uses 15-minute block averaging periods starting at midnight. The current draft PAR 1118 language would require flare tip velocity standards to be met at all times and averaged over 15 minutes. This would cause several types of conflicts between the two regulations. For example:

- Flaring events (less than 15 minutes) not subject to the RSR flare tip velocity standard could be subject under draft PAR 1118
- Flare tip velocity averaging periods could be different since RSR periods are pegged to midnight start
- Flare tip velocity standards are not the same; RSR regulation requires flare tip velocity to be less than 60 fps or less than 400 fps **and** V_{max} whereas Draft PAR 1118 language specifies "less than 60 fps or the lesser of 400 fps **or** V_{max}."

11-5

While these differences may seem small, they could create compliance difficulties and also conflict with the stated objective to harmonize Rule 1118 requirements with EPA RSR regulations. These potential issues can be easily avoided by directly incorporating the RSR specifications.

Proposed Change

(c)(3) All flares at petroleum refineries shall be operated such that the flare tip velocity is maintained 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 63.670).

~~Except as specified in (c)(10), operate all flares at petroleum refineries such that the flare tip velocity averaged over 15 minutes is less than:~~

(A) ~~60 feet per second, or the lesser of 400 feet per second or VMax, where:~~

$$\cancel{Log_{10}(V_{Max}) = \frac{Net\ Heating\ Value_{Vent\ Gas} + 1{,}212}{850}}$$

~~and the Net Heating Value~~$_{Vent\ Gas}$ in British Thermal Units per standard cubic foot is ~~determined pursuant to monitoring required in subdivision (g).~~

2. Section (c)(4), Net Heating Value of Flare Combustion Zone (NHVCZ)

The language in this new section should be clarified to reflect that the requirement is intended to apply only to General Service Flares.

The current draft language requires "flares at petroleum refineries" to "maintain the net heating value of the flare combustion zone gas (NHVCZ) at or above 270 British Thermal Units per standard cubic feet, averaged over a 15-minute period. The owner or operator shall calculate NHVCZ as specified in subparagraph (g)(9)(C). Section (g)(9)(C) is applicable to general service flares." This requirement was only intended to apply to General Service Flares; not flares for Clean Service Streams. The following revision is proposed. 11-6

Proposed Change
(c)(4) Effective January 30, 2019, General Service Flares ~~flares~~ at petroleum refineries shall maintain the net heating value of the flare combustion zone gas (NHVcz) at or above 270 British Thermal Units per standard cubic feet, averaged over a 15-minute period. The owner or operator shall calculate NHVcz 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.

3. Section (c)(6)(A), Specific Cause Analysis - VOC Threshold

As noted in Attachment B, the VOC emission factor is proposed to increase by a factor of 10. For this reason, the flare event threshold for VOC emissions should be increased by a corresponding amount. Furthermore, the Flare Event definition in Section (b)(5) needs to be revised as noted above. 11-7

Proposed Change
(c)(6)(A) Emissions exceed 1000 ~~1200~~ pounds of VOC; or

4. Section (c)(9), Specific Cause Analysis Requirements

Proposed language requires that all corrective actions identified in the Specific Cause Analysis shall be implemented within 45 days of the flare event, and the Executive Officer may be petitioned to grant an extension. WSPA recommends the same time requirements for corrective actions as EPA RSR to prevent potential conflicts.

Proposed Change 11-8
(9) All corrective actions identified in a Specific Cause Analysis required under paragraph (c)(6) or (c)(7) shall be implemented within 45 days, or as soon as practicable, of the flare event for which the Specific Cause Analysis was required. ~~The operator may petition the Executive Officer to grant a longer implementation period by demonstrating that such period is the shortest practicable.~~

5. Section (c)(13)(B), Scoping Document - Annual Emissions Levels

The revised draft language added a new requirement to analyze the feasibility of achieving an annual emission level of 0.1 tons per year of volatile organic compounds for planned flare events and essential operational needs for flares that only vent clean service streams. Staff has provided no basis for including clean service stream flares in the Scoping Document and no basis for the specified annual emissions target. Clean service streams represent, by definition, cleaner streams which inherently have a low sulfur content. These streams are typically covered by other District rules and routing these streams to other (non-flare) equipment (e.g., thermal oxidizer, etc.) could provide no environmental benefit and/or could compromise process safety. For these reasons, WSPA recommends that this requirement should be deleted from the rule. 11-9

Proposed Change
~~(c)(13)(B) 0.1 tons per year of volatile organic compounds from flares that only vent clean service streams.~~ 11-9 cont'd

6. Section (c)(13)(C), Scoping Document – Flaring Alternatives

The revised draft language requires Scoping Documents to "…analyze the feasibility of installing and maintaining at least three physical systems 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)" WSPA recommends that this language be revised to cover both physical systems and operational systems, which is consistent with Scoping Document alternatives described in (c)(13)(A). 11-10

Proposed Change
(c)(13)(C) Using the criteria described in clauses (c)(13)(A)(i) through (iv), the Scoping Document shall analyze the feasibility of installing and maintaining ~~maintening~~ at least three physical or operational systems 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).

Section (f), Flare Monitoring and Recording Plan Requirements

1. Section (f)

Contiguous facilities under common control/ownership as defined under Title V should be allowed to submit one Flare Monitoring and Recording Plan. Section (f) should be amended to explicitly authorize such an approach. 11-11

Proposed Change (New Subsection)
(f)(5) The owner or operator of an existing petroleum refinery, sulfur recovery plant or hydrogen production plant may submit a single flare monitoring and recording plan to cover two or more contiguous covered facilities if under common control/ownership.

2. Section (f)(4)(E)

The District has revised Section (f)(4) to require detailed process flow diagrams be included in Flare Monitoring and Recording Plans. Such diagrams may be considered Confidential Business Information (CBI) and companies may be concerned about the District's ability to provide appropriate CBI protection for the diagrams. Unless the District can guarantee appropriate protection in the Flare Monitoring and Recording Plans for CBI material, WSPA recommends that the language in this section be reverted back to the prior version. 11-12

Proposed Change
(E) ~~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. A representative flow diagram showing the interconnections of the flare system(s) with vapor recovery system(s), process units and other equipment as applicable.~~ A representative flow diagram showing the interconnections of the flare system(s) with vapor recovery system(s), process units and other equipment as applicable.

Section (g) Operation, Monitoring and Recording Requirements

1. Section g(7) 11-13

The District has revised the section in an attempt to harmonize video monitoring and recording requirements for visible emissions with EPA RSR. WSPA recommends adding clarifying language addressing monitoring required by Rule 1118 prior to the EPA RSR deadline, as well as referencing EPA RSR directly for new monitoring requirements to alleviate any confusion. 11-13 cont'd

Proposed Change

(7) Effective July 1, 2006, 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 flame at a rate of no less than one frame per minute. Effective January 30, 2019, 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 elevated flares, and a sufficient area above the flame of all flares that is suitable for visible emissions observations, ~~at a rate of no less than one four frames per minute~~ as required per Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

2. Section g(9)(A)

The proposed Section g(9)(A) requires that "no later than January 30, 2019, for all general service flares" facilities "install, operate, calibrate, maintain, and record data from any monitoring systems" required by EPA RSR. EPA RSR allows for a one-year extension for the installation, operation, and calibration of required flare monitoring systems, and WSPA recommends that the language in this section align with EPA requirements. 11-14

Proposed Change

(9) No later than January 30, 2019, or as extended accordingly per Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries , for all general service flares:

(A) Install, operate, calibrate, maintain, and record data from any monitoring systems required by Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries that are not already required by paragraph (g).

Section (i), Notification and Reporting Requirements

1. Section (i)(5)

This language should be revised to specifically include the District's 24-hour hotline or similarly recorded telephone number. 11-15

Proposed Change

(5) If the Web-Based Flare Event Notification System is not available, or if functions within the Web- Based Flare Event Notification System do not allow facilities to enter the necessary information required in (i)(2) through (i)(4), then notifications shall be made to 800-CUT-SMOG (288-7664). ~~the Executive Officer by telephone.~~

Section (k), Exemptions

1. Section (k)(1)

This section needs to be revised to include references to Net Heating Value (NHV) and NHV analyzers. 11-16

Proposed Change 11-16 cont'd

(k)(1) Notwithstanding a flare monitoring system, consisting of a flow meter, higher heating value analyzer, Net Heating Value (NHV) analyzer, and total sulfur analyzer that is in operation, sampling and analyses of representative samples for higher heating values, Net Heating Value (NHV), and total sulfur concentration pursuant to paragraph (g)(3) may not be required for any flare event that…

2. Section (k)(2)

Section (k)(2) should be clarified to exempt flaring events caused by or resulting from external power curtailments, natural disasters or acts of war or terrorism. WSPA recommends the following changes to the language.

Proposed Change

(k)(2) ~~Any sulfur dioxide emissions from flareing~~ Flaring events and any associated emissions caused by, or resulting from, external power curtailment beyond the operator's control, (excluding interruptible service agreements), natural disasters or acts of war or terrorism shall not count towards either: 11-17

(A) The performance targets specified in subdivision (d) upon submittal of documentation proving the existence of such events and certified in writing by the petroleum refinery official responsible for emission reporting; or

(B) The prohibitions listed in paragraph (c)(10).

If you have any questions concerning these comments, please contact me at (310) 808-2146 or by email at bmccann@wspa.org.

Sincerely,

cc: Cathy Reheis-Boyd,
WSPA Patty Senecal, WSPA

Response 11-1
Thank you for your comments. Specific responses are included in Responses 10-2 through 10-17 below.

Response 11-2
Relief valve leakage is still proposed to be removed from the definition of Essential Operational Needs. The commenter is concerned that any leakage that occurs during a flare event when the water seal is broken will be vented out the flare tip. Paragraph (c)(14) requires that no vent gas can be *"combusted except during emergencies, shutdowns, startups, turnarounds or essential operational needs."*, however it does not place limits on where the vent gas is generated from. So if flaring is occurring because of an allowed flaring event such as an emergency, any vent gases that are released from activities normally captured by the flare gas recovery system will not be distinguishable from the vent gases associated with the emergency. Therefore any flared gases from relief valve leakage during an allowed flare event would not be considered a violation of the rule, unless the leakage itself was the cause of the flare event and violated another part of the rule such as the prohibitions in paragraph (c)(10).

Response 11-3
See Response 10-2. Gases from intermittent minor venting released during an allowed flare event would be indistinguishable from the gases that are associated with the flare event itself. The release of the intermittent minor venting in this instance would not be a violation of the rule, unless the minor venting itself was the cause of the flare event and violated another part of the rule such as the prohibitions in paragraph (c)(10).

Response 11-4
No change is proposed in response to this comment. The commenter states that the proposed change would represent a significant change to the rule when considered together with the per event requirements in the rule, but the commenter does not state why the new language should be removed. The proposed change is designed to address situations where a process unit may be repeatedly causing flaring just below Rule 1118 thresholds, but is not addressed because there are no thresholds exceeded. The proposed change to the definition will require that all flare events within 24 hours from one process unit be evaluated against Rule 1118 thresholds.

Response 11-5
The comment states that the proposed rule language is inconsistent with the EPA Refinery Sector Rule (RSR) for three reasons. Two changes have been made in response to ensure that PAR 1118 is consistent with the EPA RSR. First, the definition for flare tip velocity in (b)(9) has been revised to measure the velocity in 15 minute blocks, beginning at 12 midnight. Second, (c)(3) has been changed to require that the flare tip velocity be maintained less than 60 feet per second, or the lesser of 400 feet per second **and** V_{Max}. These two changes align the requirements in the EPA RSR with PAR 1118 and address the concerns raised by the commenter.

Response 11-6
The requested change has been made to maintain consistency with the EPA RSR.

Response 11-7

The requested change has not been incorporated into PAR 1118. The previous threshold was 100 pounds for VOC, and a change to 200 pounds was proposed in the recent draft rule language sentto the working group. After hearing concerns from other stakeholders that questioned why the existing emissions threshold would not be applicable in the future, PAR 1118 now proposes to retain the existing VOC threshold at 100 pounds.

Response 11-8

In response to this comment, paragraph (c)(9) has been changed, with italicized sections below indicating the change from the previously proposed rule language.

(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)* *The Executive Officer may require a modification to the schedule, including increments of progress, and shall notify the operator in writing with an explanation describing why the justification is not sufficient.*

Response 11-9

No change has been made in response to this comment. The purpose of Rule 1118 is to reduce all flare related emissions, not just SOx. The proposed emission level of 0.1 tons of VOC per year that must be analyzed within the Scoping Document represents the median level of emissions from all clean service flares from 2012 to 2016. Further, five out of the seven clean service flares subject to Rule 1118 have achieved this annual level more than once during this five year period. Further, if this level were achieved during this five year period, it would have reduced VOC emissions by about 27 total tons using emission factors currently in Rule 1118. As shown in the first Working Group presentation, and in Figure 4 of this staff report, clean service streams represent a significant portion of VOC emissions from flaring. Further, with the ROG (i.e. VOC) emission factors for propane and butane increasing by about a factor of three in PAR 1118, the potential emissions reductions at this level could be even greater. In order to evaluate the feasibility of reducing these emissions, facility operators will evaluate the feasibility of achieving this emissions level within the Scoping Documents as required by PAR 1118.

Response 11-10

Subparagraph (c)(13)(C) has been modified in response to this comment as shown below in italics.

(D) 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).

Response 11-11

No change has been made in response to this comment. If a facility has an integrated operation, they are already allowed to apply to operate under a single Flare Monitoring and Recording Plan.

Response 11-12

Subparagraph (f)(4)(E) has been changed as shown below in response to this comment. This proposed change should ensure that confidential business information is not included in Flare Monitoring and Recording Plans.

(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.

Response 11-13

In response to this comment, paragraph (g)(7) has been modified as shown below.

(7) 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, monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare, the flame of flares that are not enclosed, and a sufficient area above the flame of all flares that is suitable for visible emissions observations, at a rate of no less than one frame every 15 seconds.

Response 11-14

No changes have been made in response to this comment. If a facility chooses to apply for an extension of any requirement of the EPA RSR, the equivalent provision within Rule 1118 can also be extended through existing District procedures, such as a request for a variance from the SCAQMD Hearing Board.

Response 11-15

The requested modification has been made in paragraph (i)(5).

Response 11-16

The requested modification has been made in paragraph (k)(1). Although Net Heating Value analyzers are not required in Flare Monitoring and Recording Plans, they are required to be installed pursuant to (g)(9) in the incorporation of the EPA RSR.

Response 11-17

Paragraph (k)(2) has been modified as shown below in italics in response to this comment. The modifications were made to make the exemption specifically apply to limits that are described in the rule.

(2) Any sulfur dioxide emissions, *visible emissions prohibited in paragraph (c)(10), and flare tip velocities that exceed limits in subparagraph (c)(3)(A)* from flare events caused by external power curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters or acts of war or terrorism shall not count towards either…

Comments Received at the May 11, 2017 Public Workshop

The following comments were received at the Public Workshop for Proposed Amended Rule 1118 held on May 11, 2017 at the SCAQMD headquarters in Diamond Bar.

PWS-1 Comment Video image extracts of flaring should be saved for five years.

PWS-1 Response PAR 1118 requires facilities to save video recordings, with one frame every 15 seconds, for five years.

PWS-2 Comment More monitoring should be conducted of flaring emissions, including for SOx, hydrogen sulfide, and hydrogen cyanide. Hydrogen cyanide emissions have been increasing at refineries based on EPA's Toxics Release Inventory Database, and hydrogen sulfide emissions are also high (see scanned handout from commenter on next page).

PWS-2 Response Monitoring of gases that are vented to the flare is already required by Rule 1118. These instruments monitor gases before they are combusted and vented to the atmosphere. One of the instruments is a sulfur analyzer, and the results from this instrument are used to determine the SOx emissions from every flare event. In addition, Rule 1118 already prohibits the combustion of vent gases with a hydrogen sulfide concentration exceeding 160 ppm. This limit was set to ensure that ambient air quality standards are not exceeded for hydrogen sulfide.

Finally, although hydrogen cyanide is reported as an emitted pollutant from refineries, staff has researched the annual emissions reports from refineries in the SCAQMD and none have reported hydrogen cyanide emissions from flaring. Staff was also unable to find research pointing to methods to quantify hydrogen cyanide emissions from flaring without conducting sampling of the flare emissions themselves. Hydrogen cyanide is not a known product within vent gas systems, however in some cases it could be created an intermediate product of hydrocarbon combustion. Because of the height of flare stacks, and the very high temperatures, it is generally considered infeasible to take samples of the post-combustion plume of refinery flares. However, in parallel with this rulemaking effort, an Optical Remote Sensing pilot study is proposed that may have the potential to evaluate individual compounds in the flare plume. As part of the upcoming Request for Information being released for this study, staff will include criteria that responses should include what their instrument's capabilities are with regard to detecting toxics emissions, such as hydrogen cyanide.

PWS-3 Comment Rule 1118 should be extended to all petroleum related facilities.

PWS-3 Response PAR 1118 does not propose to extend the applicability of the rule to other facilities, however Proposed Rule 1118.1 is being developed now and will apply to other facilities.

PWS-4 Comment A Specific Cause Analysis is different than a root cause analysis. Rule 1118 should require root cause analyses like is required for other regulations (see scanned OSHA fact sheet from commenter in following pages).

PWS-4 Response Root cause analyses from different regulations may have different requirements because they serve different purposes from Specific Cause Analyses (SCAs). The purpose of SCAs within PAR 1118 is to investigate the cause of a flare event, identify corrective measures and prevent recurrence of a similar event. The analysis contained within a SCA required in PAR 1118 is equal to the root cause analyses required in the EPA Refinery Sector Rule (RSR), but more flare events require SCAs due to PAR 1118 requirements than are required from the EPA RSR.

PWS-5 Comment Rule 1118 should require facilities to replace equipment throughout the refinery following the manufacturer's recommended schedule.

PWS-5 Response PAR 1118 already prohibits flaring if it is caused by poor maintenance. This suggestion and others will be considered in the second phase of rulemaking that is designed to take a more comprehensive look at measures to reduce flaring emissions even further.

PWS-6 Comment The definition for Essential Operational Needs should be tightened with regard to the sudden shutdown of refinery fuel gas combustion devices.

PWS-6 Response This definition has been revised so that shutdowns caused by a breakdown or emergency are no longer allowed as an Essential Operational Need.

PWS-7 Comment Monitoring should be required of the emitted flare plume, either with a crane or with drones.

PWS-7 Response Even with cranes or other mechanical collection devices there are inherent hazards and logistical challenges in physically attempting to collect flare emissions directly from the flare plume where temperatures exceed 1000 degrees Fahrenheit at heights well above 100 hundred feet. In parallel with the proposed rulemaking, staff is proposing to initiate an Optical Remote Sensing pilot study to evaluate the ability of emerging technologies to monitor flaring emissions at the combustion zone. This approach is believed to be the most promising and feasible for directly evaluating flaring emissions as an alternative to using emission factors.

PWS-8 Comment Flaring emissions affect public health. When asked about a flaring event, personnel from a refinery didn't provide the information requested by the commenter. The commenter also stated that refineries can't be trusted to monitor themselves, or to hire consultants to conduct analyses of health impacts from their facilities due to financial conflicts of interest. The commenter further stated that District staff is unable to conduct independent evaluation of refineries because an SCAQMD Board Member has received financial benefit from refineries.

PWS-8 Response One of the purposes of PAR 1118 is to control and minimize flaring and flare related emissions which could affect public health. Since Rule 1118 was adopted in 1998, and amended in 2005, flaring has reduced substantially. Although the requirements in PAR 1118 require refineries to conduct many analyses, these are conducted under the strict oversight of the District, and must adhere to guidelines from the District and other agencies, such as the state or federal EPA. Staff is unaware of any conflict of interest that would impact the compliance and enforcement activities of District staff as these activities are conducted independently of our Board. The proposed amendments will place new limits on flaring and flare emissions, and a second phase of rulemaking is being proposed to reduce flaring emissions further.

PWS-9 Comment Flare Minimization Plans should be conducted for all refineries.

PWS-9 Response See Response 5-2 in response to the same comment in writing from the same commenter.

PWS-10 Comment Flaring is a short term event, and long term annual thresholds should not be the only means of limiting flaring emissions.

PWS-10 Response The commenter is correct that flaring is typically a short term activity, however there are many provisions within PAR 1118 and the existing Rule 1118 to limit flaring besides annual thresholds. This includes newly proposed prohibitions on smoking flaring events, requirements for Specific Cause Analysis and corrective actions based on thresholds for individual flare events, notification thresholds for individual flare events, and monitoring and reporting of every flare event, regardless of size. Additional measures to reduce individual flare events is being pursued in a second phase of rulemaking that will be based on detailed feasibility studies that facilities will be required to prepare by PAR 1118.

PWS-11 Comment The ROG emission factor for clean service streams such as propane and butane is too low.

PWS-11 Response See Responses 5-3 and 7-1 in response to the same comment in writing from the same commenter.

PWS-12 Comment An assumption that flaring always occurs with 98% destruction efficiency is not appropriate and should not be assumed in PAR 1118.

PWS-12 Response The U.S. EPA investigated destruction efficiency when updating its emission factor guidance and when developing its updates to the Refinery Sector Rule (RSR). PAR 1118 incorporates many of the key elements of the U.S. EPA RSR that are designed to improve the destruction efficiency of flaring, including limits on flare tip velocity and on the net heating value of the combustion zone. There are currently no feasible methods that have been found to directly measure destruction efficiency continuously at a refinery, so PAR 1118 relies on emission factors based on tests that have been conducted in a more controlled environment. In order to pursue more direct methods of evaluating the destruction efficiency and emissions from flaring, staff is proposing to initiate an Optical Remote Sensing pilot study to determine if new emerging technologies are able to provide continuous measurement of flaring emissions, including destruction efficiency.

PWS-13 Comment	All flaring data should be placed online by flare event.
PWS-13 Response	No changes are proposed in PAR 1118 as the placement of flaring data online is an activity that is not governed by Rule 1118. Staff is exploring how to enhance the release of and access to flaring data and will continue to work with all stakeholders on this issue.
PWS-14 Comment	Flaring from Essential Operational Needs should not be allowed as it isn't allowed by the Bay Area AQMD.
PWS-14 Response	See Response 5-5 in response to the same comment in writing from the same commenter.
PWS-15 Comment	PAR 1118 should focus on prevention rather than restricting activities post-emissions.
PWS-15 Response	PAR 1118 includes a requirement that facilities conduct a forward looking Scoping Document that analyzes the feasibility of implementing measures to reduce flaring further. There are also existing limits within Rule 1118 that prevent flaring through disincentives (such as Mitigation Fees) or prohibitions (such as limits on smoking flaring).
PWS-16 Comment	The community should be engaged more by the District on flaring notifications, including through community groups, and on who the 3rd party consultant should be that will assist in reviewing Scoping Documents.
PWS-16 Response	District staff will engage local community groups on flaring notifications and activities, as well as the selection of consultants to review Scoping Documents submitted by refineries.
PWS-17 Comment	The proposed rule amendments are very technical, and have the potential to create conflicts with existing federal rules. Staff should consider pushing the date back for adoption of this rule.
PWS-17 Response	See Response 10-1 in response to the same comment in writing from the same commenter.
PWS-18 Comment	The Ringelmann chart should be updated for determining visible emissions as it is based on old methods for determining opacity.
PWS-18 Response	Compliance staff is trained in methods to determine plume opacity, and the Ringelmann chart is not the only method that is relied upon to determine if flaring emissions exceed visibility limits.

REFERENCES

South Coast AQMD Rule 1118 Implementation Guidelines August 2007 Version 2.0.
http://www.aqmd.gov/docs/default-source/compliance/rule-1118/r1118igd.pdf

South Coast AQMD 2012 Air Quality Management Plan Stationary Source Control Measures
http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/appendix-iv-(a)-final-2012.pdf

South Coast AQMD Technical Support Document 2012 AQMP Control Measure (MSC)-03
http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/appendix-iv-(a)-final-2012.pdf

U.S. EPA AP-42 Emission Factors, 5th Edition, Volume 1, Chapter 13.5
https://www3.epa.gov/ttn/chief/ap42/ch13/final/C13S05_12-13-16.pdf

U.S. EPA Petroleum Refinery Sector Risk & Technology Review & New Source Performance Standards (NSPS) & (NESHAPS)
https://www.epa.gov/stationary-sources-air-pollution/petroleum-refinery-sector-risk-and-technology-review-and-new-source

40 Code of Federal Regulations Part 60 Subpart Ja

40 Code of Federal Regulations Part 63 Subpart UUU

40 Code of Federal Regulations Part 63 Subpart CC

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 (SCAQMD) is the Lead Agency and has prepared a Notice of Exemption for the project identified above.

The proposed project is amending Rule 1118 – Control of Emissions From Refinery Flares. SCAQMD staff has reviewed the proposed project pursuant to: 1) CEQA Guidelines § 15002(k) - General Concepts, the three-step process for deciding which document to prepare for a project subject to CEQA; and 2) CEQA Guidelines § 15061 - Review for Exemption, procedures for determining if a project is exempt from CEQA.

As provided in CEQA Guidelines § 15306 - Information Collection, the proposed project is exempt because it will consist of basic data collection, research and resource evaluation activities and will not result in a serious or major disturbance to an environmental resource. CEQA Guidelines §15306 exempts such a project for information-gathering purposes, or as part of a study leading to future action which the agency has not yet taken. Furthermore, SCAQMD staff has determined that it can be seen with certainty that there is no possibility that the proposed project may have a significant adverse effect on the environment. Therefore, the project is considered to be exempt from CEQA pursuant to CEQA Guidelines § 15061(b)(3) – Activities Covered by General Rule. A Notice of Exemption has been prepared pursuant to CEQA Guidelines § 15062 – Notice of Exemption. If the project is approved, the Notice of Exemption will be filed with the county clerks of Los Angeles, Orange, Riverside and San Bernardino counties.

Any questions regarding this Notice of Exemption should be sent to Barbara Radlein (c/o Planning, Rule Development and Area Sources) at the above address. Ms. Radlein can also be reached at (909) 396-2716. Mr. Ian MacMillan is also available at (909) 396-3244 to answer any questions regarding the proposed amended rule.

Date: June 29, 2017 **Signature:**

Barbara Radlein
Program Supervisor, CEQA Section
Planning, Rules, and Area Sources

Reference: California Code of Regulations, Title 14

NOTICE OF EXEMPTION

To:	County Clerks Counties of Los Angeles, Orange, Riverside and San Bernardino	**From:**	South Coast Air Quality Management District 21865 Copley Drive Diamond Bar, CA 91765

Project Title: Proposed Amended Rule 1118 – Control of Emissions From Refinery Flares

Project Location: The SCAQMD has jurisdiction over 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 portions of the Salton Sea Air Basin (SSAB) and Mojave Desert Air Basin (MDAB). The SCAQMD's jurisdiction includes the federal nonattainment area known as the Coachella Valley Planning Area, which is a sub-region of Riverside County and the SSAB.

Description of Nature, Purpose, and Beneficiaries of Project: SCAQMD staff is proposing amendments to Rule 1118 that would: 1) harmonize Rule 1118 with key updates from US EPA's recent Refinery Sector Rule update regarding flares, including new prohibitions on some types of flaring; 2) require facilities subject to Rule 1118 to prepare a Scoping Document that evaluates the feasibility of minimizing or avoiding planned and unplanned flaring events; 3) remove the $4 million annual cap on mitigation fees that facilities may pay for flaring; 4) update emission factors based on US EPA's updated AP-42 guidance; and 5) update and clarify reporting requirements for facilities. In addition, SCAQMD staff is proposing to allocate up to $100,000 from the Rule 1118 Mitigation Fund to upgrade the web-based Flare Event Notification System.

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

Exempt Status:
CEQA Guidelines § 15061(b)(3) – Activities Covered by General Rule
CEQA Guidelines § 15306 - Information Collection

Reasons why project is exempt: SCAQMD staff has reviewed the proposed project pursuant to: 1) CEQA Guidelines § 15002(k) - General Concepts, the three-step process for deciding which document to prepare for a project subject to CEQA; and 2) CEQA Guidelines § 15061 - Review for Exemption, procedures for determining if a project is exempt from CEQA. As provided in CEQA Guidelines § 15306 - Information Collection, the proposed project is exempt because it will consist of basic data collection, research and resource evaluation activities and will not result in a serious or major disturbance to an environmental resource. CEQA Guidelines §15306 exempts such a project for information-gathering purposes, or as part of a study leading to future action which the agency has not yet taken. Furthermore, SCAQMD staff has determined that it can be seen with certainty that there is no possibility that the proposed project may have a significant adverse effect on the environment. Therefore, the project is considered to be exempt from CEQA pursuant to CEQA Guidelines § 15061(b)(3) – Activities Covered by General Rule.

Date When Project Will Be Considered for Approval (subject to change):
SCAQMD Governing Board Hearing: July 7, 2017; SCAQMD Headquarters

CEQA Contact Person:	**Phone Number:**	**Email:**	**Fax:**
Ms. Barbara Radlein	(909) 396-2716	bradlein@aqmd.gov	(909) 396-3982
Rule Contact Person:	**Phone Number:**	**Email:**	**Fax:**
Mr. Ian MacMillan	(909) 396-3244	imacmillan@aqmd.gov	(909) 396-3324

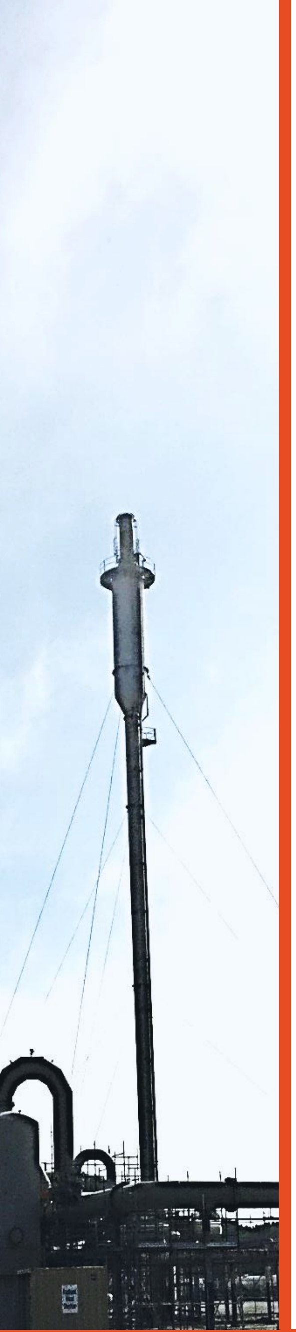
Date Received for Filing: ________________ **Signature:** *(Signed Upon Board Approval)*
Barbara Radlein
Program Supervisor, CEQA Section
Planning, Rule Development & Area Sources

ATTACHMENT I

Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

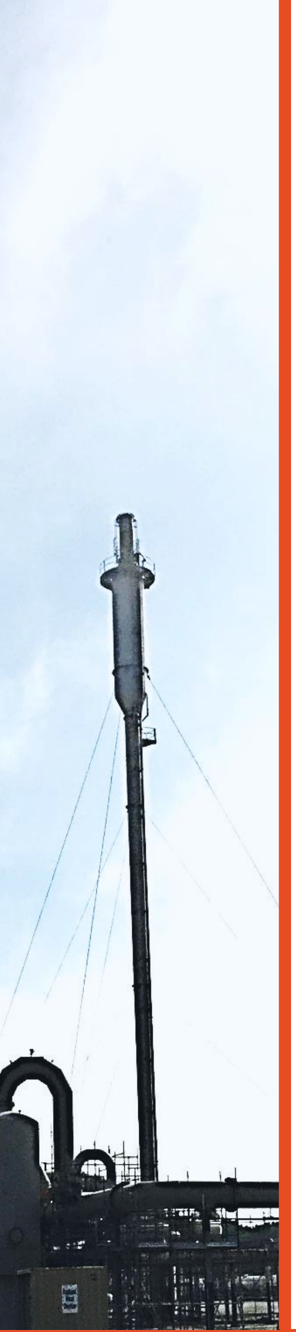
GOVERNING BOARD MEETING

JULY 7, 2017



Background

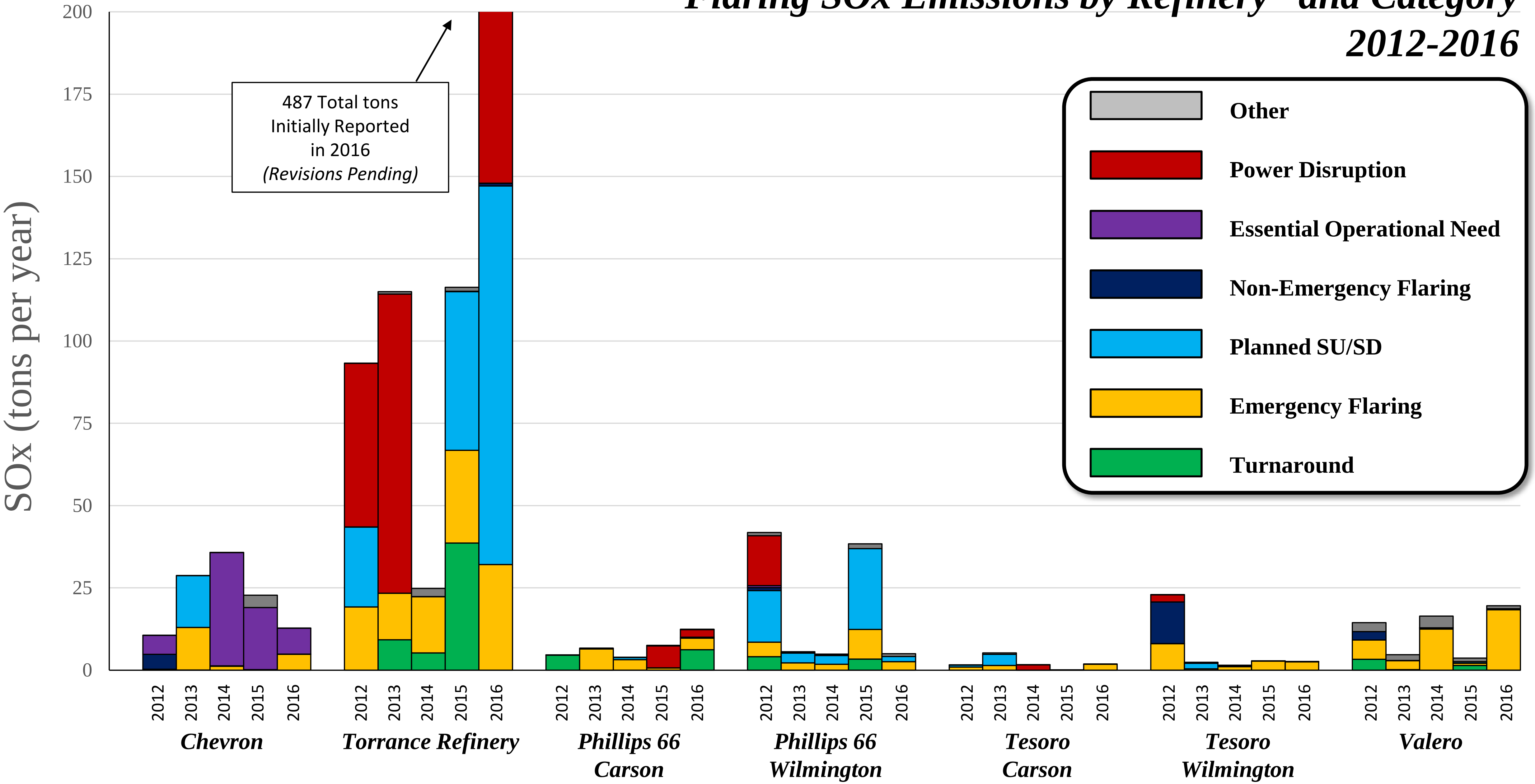
- Flaring provides two important functions in the refining process
  - Critical safety feature to control combustible gas releases
  - Reduces emissions of some pollutants through combustion
- Rule 1118 last amended in 2005
  - Requires: flare gas monitoring, payment of mitigation fees if flaring emissions above annual performance target, reporting, notification
  - Prohibits some types of flaring



Need for Rule 1118 Amendments

- Flaring events and related emissions from refineries have declined in past decades, but significant flaring still occurs
  - 1,179 tons SOx reported between 2012-2016, or ~3% of air basin total SOx
  - Other pollutants emitted include PM, VOC, toxics
- Key EPA updates:
  - December 2015 – Refinery Sector Rule
  - May 2015 – Startup / Shutdown / Malfunction Rule
  - 2008, 2016 – Flaring emission factors
- 2012 AQMP
  - MCS-03 – Improved Startup, Shutdown, Turnaround Procedures

Flaring SOx Emissions by Refinery* and Category 2012-2016



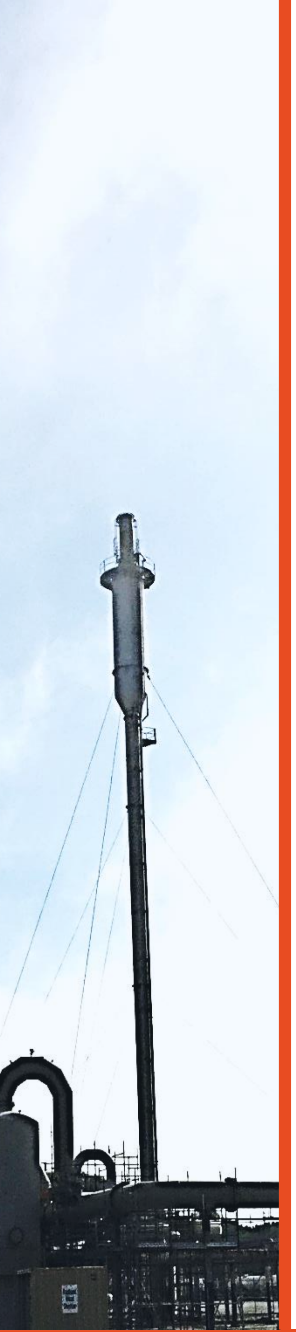
*All other Rule 1118 facilities emitted <1.0 tons SOx cumulatively between 2012-2016

Rule 1118 Proposed Amendments

- Phase I (*now*)
  - Incorporation of key portions of EPA Refinery Sector Rule
  - Facilities must prepare Scoping Document to evaluate feasibility of avoiding or eliminating flaring
  - Remove $4 million annual cap on Mitigation Fees
  - Update Notification and Reporting requirements
  - Update VOC emission factors
  - Remove outdated provisions
- Phase II (*future*) – Use data from Scoping Documents and proposed Optical Remote Sensing study to reduce flaring emissions further

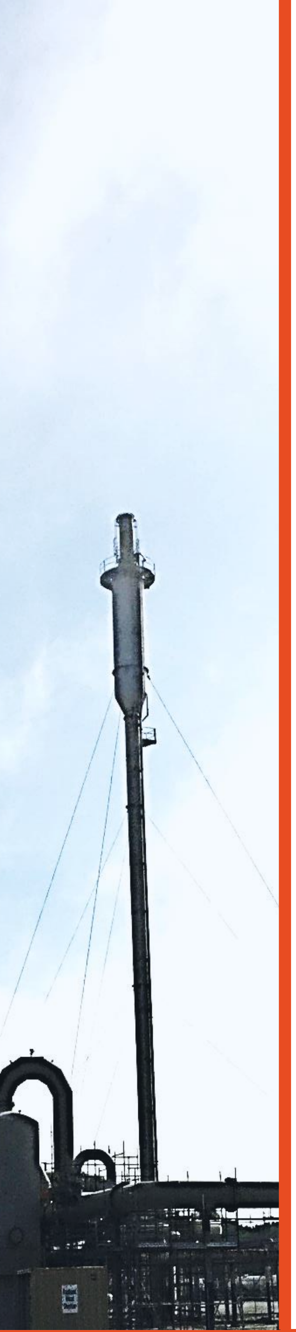
Key Stakeholder Concern
VOC Emission Factor – Vent Gas

- Vent Gas emission factors increasing ~10 times
  - Yields more Specific Cause Analyses (SCAs) and Notifications
    - Definition of Flare Event changing – multiple events in one day caused by the same process unit would now be one event
  - Industry requesting a higher VOC threshold for SCAs and Notification
  - Community groups have requested to keep VOC threshold at current level of 100 pounds
  - Staff recommending to keep VOC threshold at current level
    - Consistent with previous Board decision
    - Anticipated increase in workload not overly burdensome



Key Stakeholder Concern
VOC Emission Factor – Propane/Butane

- Propane/Butane emission factor increasing ~3 times
  - Affects flares venting pure propane or butane tanks
  - Community group requesting to use Vent Gas emission factor for butane/propane flaring
    - Vent Gas emission factor ~73 times higher than proposed propane/butane emission factor
  - Staff proposing to use EPA emission factor for propane/butane combustion from boilers
    - Proposed emission factor is fuel-specific (pure propane / butane)
      - Lighter hydrocarbons burn cleaner than heavier hydrocarbons
      - Vent Gas emission factor is based on a blend of hydrocarbons found in refinery fuel gas
    - Proposed Optical Remote Sensing study seeking to move away from emission factors and toward monitoring of post-combustion emissions
      - Staff will report back to Stationary Source Committee if study finds updates to emission factor needed



Staff Recommendation

- Determine that project is exempt from CEQA
- Adopt Board Resolution
- Adopt Amendments to Rule 1118