SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

FINAL STAFF REPORT FOR

PROPOSED AMENDED RULE 1118 –– CONTROL OF EMISSIONS FROM REFINERY FLARES

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Deputy Executive Officer
Planning, Rule Development, and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
VOC Rule Development
Larry M. Bowen, P.E.

Author:	Eugene Teszler	AQ Specialist
Reviewed by:	Ed Muehlbacher, P.E.	Program Supervisor
	Jeri G. Voge	Sr. Deputy District Counsel
Contributors	Pang Mueller, P.E.	Sr. Manager
	Paul Park	Sr. AQ Engineer
	Abe Udobot	AQ Engineer
	Zach Muepo	AQ Inspector
	Glenn Kasai	AQ Engineer
	Raul Dominguez	AQ Chemist
	Kathy Kasza	AQ Chemist
	Jeff Cox	AQ Engineer
	Sharon Garrett	AQ Inspector

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EXECUTIVE SUMMARY

Rule 1118 – Emissions from Refinery Flares was originally adopted by the South Coast Air Quality Management District (AQMD) on February 13, 1998, with the purpose of monitoring, recording and reporting data on petroleum refinery flaring and related operations. This represented Step I of Control Measure CMB-07 of the 1997 Air Quality Management Plan (AQMP) that targets emission reductions from refinery flares, also found in the 2003 AQMP. Pursuant to the AQMD Board's direction upon the adoption of the rule, staff analyzed the monitoring data submitted by refineries in the time period from October 1, 1999 through December 31, 2003 and compiled the "Evaluation Report on Emissions from Flaring Operations at Refineries".

Staff presented the report at the September 3, 2004 AQMD Board Meeting and concluded that emissions from refinery flares were significant enough to warrant the implementation of controls. The report suggests possible ways of reducing emissions through the prevention of flaring of excess fuel gas, the elimination of leaks from pressure relief devices and the reduction of emissions during routine flaring. These objectives can be achieved by installing flare gas recovery systems and gas treating systems, expanding current capacities of flare gas recovery and treatment systems already in place, and conducting surveys to detect leaking pressure relief devices. The report also recommended improvements in the measurement of flare vent gas flows and the installation of continuous monitoring systems to measure the total sulfur gas concentration and the higher heating value of the flared gas, as well as the standardization of methodologies for flow and emissions calculations and for missing data substitution. Following the report presentation, the AQMD Board directed staff to amend Rule 1118 – Emissions from Refinery Flares, and implement Step II of Control Measure CMB-07. Step II of the control measure aims to reduce emissions of criteria pollutants from refinery flares by identifying and requiring the most feasible and cost-effective control options available.

The air quality objective for the Proposed Amended Rule (PAR) 1118 is to help AQMD attain state and federal air quality standards by minimizing emissions of criteria air contaminants and their precursors from flaring activities at petroleum refineries. The proposed amendment would eliminate the flaring of vent gases except for those resulting from emergencies, shutdowns and startups, turnarounds and essential operational needs; establish operational requirements of diagnostic practices to minimize flaring.

The proposed amendment establishes refinery specific performance targets for flare-related total sulfur emissions, calculated as sulfur dioxide, at 1.5 tons per million barrels of crude process~~ed~~ing capacity in calendar year 2006, 1 ton per million barrels of crude process~~ed~~ing capacity in calendar year 2008, 0.7 tons per million barrels of crude process~~ed~~ing capacity in calendar year 2010, and 0.5 tons per million barrels of crude process~~ed~~ing capacity in calendar year 2012, respectively, based on the 2004 industry-wide ~~throughput~~processing capacity. During the rule development process, industry identified an inequity of using crude throughput versus crude capacity based on a fixed year of 2004 to establish annual SO_2 performance targets. In any one year, any refinery could be conducting a shutdown or turnaround of a major crude processing unit, which could reduce crude throughput for that baseline year reflecting an artificially low baseline throughput for that refinery. Whereas crude processing capacity more accurately allocates refinery emissions based on normal refinery operations. Local refineries are operating at near capacity; therefore, the difference in emissions impact and reductions based on throughput or capacity are minimal. Excess flare related total sulfur emissions would be subject to mitigation fees of $25,000, $50,000 or $100,000 per ton, depending on whether excess emissions are no more than ten percent, greater than twenty percent but less than twenty percent, or more than twenty percent, respectively, of the annual performance targets. Excess emissions would also trigger the submittal of a flare minimization plan by the refinery and a possible issuance of a Notice of Sulfur Dioxide Exceedance by the Executive Officer. Emissions resulting from external power curtailment, natural disasters or acts of war or terrorism will be exempt from being counted towards these limits.

The proposed amendment, in keeping with the recommendations from the "Evaluation Report on Emissions from Flaring Operations at Refineries", will also enhance monitoring requirements to improve data reporting accuracy, primarily requiring the use of higher heating value analyzers and also total sulfur analyzers pending the result of a pilot test feasibility study taking place at one of the refineries. Until the analyzers are installed, but no later than July 1, 2007, the sampling frequency of flare events would be increased to daily from weekly. In addition, the rule will require the flare gas flow meters to be installed in a representative location or be upgraded with totalizing capability such that only an accurate flow to the flare is registered. The amended rule will also establish uniform missing data procedures and calculations for reporting emissions during monitors' downtime periods.

The amended rule will set new notification requirements for flaring events, as well as reporting, which will require quarterly reports to be submitted in an electronic format certified by the facility official and approved by the Executive Officer. Each petroleum refinery will submit a detailed technical description of the flare system, including an audit of vent gas recovery capacity, a summary of the flaring emissions reductions achieved to date and future planned flare emission reductions.

The emissions reductions associated with proposed amendments are estimated to be 1.18 tons per day of SO_2 and 1.44 tons per day overall for all criteria pollutants, excluding carbon monoxide, from the emissions baseline average (2002-2004) to 2012. The cost-effectiveness is estimated to be between $~~3,922~~5,524 and $~~6,926~~8,620 per ton of SO_2 reduced. When considering additional reductions in NOx, VOC and PM10, the cost effectiveness ranges between $~~3,112~~4,527 and $~~5,675~~7,063 per ton of pollutant reduced.

The proposed amended Rule 1118 is considered a "project" as defined by the California Environmental Quality Act (CEQA), and the AQMD is the designated lead agency. Pursuant to CEQA and AQMD Rule 110, the AQMD prepared an environmental assessment (EA) evaluating potential adverse significant impacts associated with implementing the proposed amended rule. The EA concluded that implementing PAR 1118 would have no significant impacts on the environment. An environmental impact is defined as an impact to the physical conditions that exist within the area which would be affected by the proposed project.

CHAPTER I

BACKGROUND

A. RULE HISTORY

The concept of reducing emissions from petroleum refinery operations was originally formalized in the 1982 Air Quality Management Plan (AQMP) as Measure A15. Measure A15 proposed increasing the use of blowdown and vapor recovery systems to reduce emissions from flares. Consideration of adoption in 1985 was postponed to provide additional time to collect background information regarding flaring operations and alternative control options. Measure A15 has been carried over through subsequent AQMPs and in the 2003 AQMP takes the form of Control Measure CMB-07.

In 1984, the Citizens for a Better Environment (CBE) petitioned the California Air Resources Board (CARB) to make a determination of the technological feasibility, availability and economic reasonableness of continuous emission monitors for refinery flares. CARB granted the CBE request and contracted a study with an engineering firm to evaluate the feasibility of continuously monitoring flaring operations at petroleum refineries. The study found that no refinery in California accurately monitored flow rates to its flares. Several types of flow meters had been installed on refinery flares, but the instrumentation could only provide relative flow information because the gas density varies and gas constituent data is necessary to calculate flow accurately. The study concluded that continuous monitoring of flare gas flow rates, gas composition and remote monitoring of flare plumes were practicable but would require substantial further development before they could be considered ready to use for accurate and precise measurements on flares at a reasonable cost.

Despite concluding that the aforementioned devices still required substantial development, the study found that devices which constantly monitored the on/off status of refinery flares were not only practicable, but were also ready to use at a relatively inexpensive cost. In 1986, CARB determined that monitoring devices were technologically feasible, available and economically reasonable for limited applications to identify and record continuously the on/off status of refinery flares in order to better quantify flare emissions. This finding was formalized and adopted by CARB as Resolution No. 86-60. CARB also encouraged local air pollution control districts to adopt rules requiring refineries to install on/off status monitors and collect flare gas composition data so that a suggested control measure for the control of emissions from refinery flares could be developed.

In 1987 through 1988, refineries in the South Coast Air Basin participated in a flare study resulting from CARB Resolution No. 86-60. The results of this study met with limited success. Staff’s review of the available data has determined that the results of the study are insufficient to quantify the emissions from petroleum refineries, especially in light of the recent refinery modifications to produce clean fuels. In addition, the previous monitoring equipment used in this study was found to be maintenance intensive and is no longer used by the refineries.

Since 1988, staff has tracked the development of available technology that could accurately monitor gas flare parameters which would result in sufficient data to quantify emissions. Recent advances in technology have resulted in devices that can now accurately monitor gas flare parameters. Staff has found that these monitoring devices are currently being used in various industries that use gas flares with favorable results.

In 1993 and 1994, staff required two refineries to conduct flare system studies as a result of frequent complaints of odor from emissions associated with their gas flaring operations. Recommendations based on these studies were implemented and resulted in a significant reduction in violations of Rule 402 – Public Nuisance. These studies and subsequent implementation of recommendations showed that each refinery flare system is complex and unique, but that opportunities do exist to reduce nuisance problems associated with refinery flare systems.

On February 13, 1998, the AQMD 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 refineries to determine if flare emissions are significant, and b) recommend whether further controls are needed.

After evaluating the data submitted to the AQMD 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 AQMD Board on September 3, 2004. The report recommended amending Rule 1118, concluding that, although refineries had made important progress in reducing emissions since Rule 1118 was originally adopted, flare emissions, especially oxides of sulfur (SOx), were still significant enough to warrant further controls. The report suggest various ways to reduce flare emissions, such as the elimination of leaks from pressure relief devices, the installation of flare gas recovery systems and gas treating systems. In addition to focus on minimization of flare emissions, the report emphasized the potential of the amendment to improve the monitoring, reporting and emission calculation methodology in order to increase the accuracy of the data collected.

B. OTHER CALIFORNIA DISTRICTS FLARE RULES

Several other air pollution control districts in California also have flare rules. The Bay Area Air Quality Management District's (BAAQMD) Rule 12-11, adopted in June 2003, is comparable to AQMD's current Rule 1118. Rule 12-11 – Flare Monitoring at Petroleum refineries applies to refineries in the San Francisco area. The rule requires the monitoring and recording of the vent gas and the composition as well as continuously recording digital video images of the flare tip for each flare. Refineries are required to submit monthly reports in electronic format, containing daily flows and gas composition and corresponding calculated emissions of methane, non-methane hydrocarbons and sulfur compounds resulting from combustion, as well as the archived video pictures of the flares. A complementary rule, Rule 12-12 which seeks to minimize flare emissions through the use of Flare Minimization Plans was adopted in June 2005, and is similar in some respects to PAR 1118.

The Santa Barbara Air Pollution Control District (SBAPCD) also regulates flares based upon its own Rule 359 - Flares and Thermal Oxidizers, adopted on June 28, 1994. This rule applies to oil and gas production, petroleum refineries and related sources, natural gas services and transportation sources and wholesale trade in petroleum/petroleum products that operate flares or thermal oxidizers. Rule 359 specifies sulfur content limits, technology-based standards for flares and thermal oxidizers, and emission standards for oxides of nitrogen (NOx) and reactive organic compounds (ROC) and operational limits. The rule also incorporates a Flare Minimization Plan, monitoring, recordkeeping, reporting and source test requirements for ground flares. However, a review of the staff report for Rule 359 indicates that there are no petroleum refinery operations in Santa Barbara similar to the petroleum refinery operations in the South Coast Air Basin and that Rule 359 applies to non-refinery petroleum operations such as oil and gas exploration and bulk loading terminals.

Ventura County Air Pollution Control District (VCAPCD) Rule 54 - Sulfur Compounds is similar to the SBAPCD Rule 359. While Rule 54 does apply to flares, as in the case with the SBAPCD rule, Rule 54 also applies to non-refinery petroleum operations and AQMD staff is not aware of any petroleum refinery operations in the jurisdiction of VCAPCD.

C. U.S. EPA REGULATIONS (EPA)

The EPA New Source Performance Standards (NSPS), under 40CFR 60.18 – General Control Device Requirements, contains provisions for flares that control vent gases from storage tanks built after July 23, 1984, subject to 40CFR 60 Subpart Kb and from piping components that were installed after January 4, 1983, subject to Subpart GGG. 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.

Another NSPS regulation, 40CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, covers operation of combustion devices such as flares, that were built or modified after June 11, 1973 under 40CFR 60.104(a). This regulation limits the concentration of the hydrogen sulfide (H_2S) in the vent gases routed to flares to 160 ppm, averaged over three hours. However, vent gases that are combusted due to startup, shutdown, process upset or relief valve leakage are exempt from this requirement.

In 1998, EPA launched a program called “The Petroleum Refinery Initiative” consisting of a series of investigations at refineries under a multi-faceted compliance approach. One of the refinery activities targeted by the investigation was excessive flaring of acid gas (gas with high H_2S content generated during the oil refining process and from the sour water stripper) that results in large amounts of sulfur dioxide being released into the atmosphere. Also investigated was excessive hydrocarbon flaring. EPA’s position, as stated in the Enforcement Alert newsletter of October 2000, is that routine or non-emergency flaring does not constitute good air pollution practice and may be a violation of the Clean Air Act. In the newsletter, EPA states that refineries should have adequate capacity to recover and treat sour gases routinely generated in their process without resorting to flaring. Good air pollution practices also include investigating the root cause of a flaring incident and taking corrective actions to prevent recurrence in the future. In the newsletter, EPA states that a properly designed, operated and maintained flare gas recovery system is one way to minimize or avoid flaring.

In an effort to reduce excessive flaring of acid gas and emissions of SOx and NOx, EPA, to date, has entered into 15 global settlements with petroleum refiners representing more than 65% od domestic refinery capacity. The settlements now cover 76 refineries and conferences are currently ongoing with 11 more petroleum refiners who represent an additional 24 refineries. Refineries effected by the global settlements are subject to a consent degree requiring them to prepare and submit plans to minimize hydrocarbon flaring, conduct root cause analyses of flaring events and implement control options such as installing flare gas recovery systems, rerouting hydrocarbon streams away from flares or making hydrocarbon flares compliant with the provisions of 40CFR 60.104(a). By stipulating to consent decrees with EPA, the refineries agreed to undertake certain remediation and mitigation actions, pay fines and provide affirmative relief by completing environmentally beneficial projects. These aforementioned requirements of the consent decrees are, in part, the concepts on which the proposed amendment to Rule 1118 is based.

Four refineries within the AQMD's jurisdiction have entered consent decrees with EPA: Equilon Enterprises, BP West Coast Products, Chevron Products Company and Conoco Phillips. As a result of the settlements, these companies pledged to reduce SOx and other air contaminants emissions to the environment by minimizing acid gas and hydrocarbon flaring and by agreeing to subject their flares to the requirements of 40CFR 60.104 for combustion devices.

D. EQUIPMENT AND OPERATION

Flares are combustion devices used extensively in the petroleum industry to burn and dispose of excess combustible gases that are generated as part of the production processes or during a process upset. Flares are also used as safety devices to reduce the potential for fires and explosions due to unburned gaseous hydrocarbon releases. Blowdown systems are designed and installed at petroleum refineries to provide for safe containment or safe release of liquids and gases that must be disposed of in the refining process. Such systems generally consist of a series of venting manifolds which lead from the process equipment to a blowdown recovery system (i.e., storage tank, wastewater system, compressor) and flares.

Flares can be elevated like a stack where the combustion, or burn-off, takes place at the tip of the flare and the flames are visible from a distance. They can also be of the ground-flare type where the burners are concentrically located near the ground level in a shrouded, refractory lined enclosure. Both types of flares are capable of destruction of hydrocarbons and other combustible gases. However, as with any type of combustion equipment, they generate air pollutants such as NOx, SOx, carbon monoxide (CO), and particulate matter (PM), in addition to the release of reactive organic gases (ROG) which have not been completely combusted. Also, similar to any other combustion device, flares have the potential to generate toxic emissions depending on the type of gases burned and operating parameters.

Flares have a design capacity, usually expressed in pounds per hour, which represents the maximum design flow of a specific composition, temperature and pressure of vent gas that can be combusted in a particular flare. Due to federal and local regulations, most flares are designed for smokeless operation over a specified flow range, which is achieved by injecting steam or air at the flare tip to increase turbulence and allow ambient air to better mix with the hydrocarbons. The federal requirement allows refinery flare operators to operate a flare with visible emissions for up to five minutes in any two consecutive hour time period. The smokeless capacity of a flare is defined as the maximum flow to a flare that can be burned without smoke and is also expressed in pounds per hour of a specific gas composition, temperature and pressure. Typically, flares are operating in a smokeless manner in a range up to 20 percent of their maximum design flow; at higher flows the size of the pipe that would be required to provide adequate steam injection at the flare tip becomes a design challenge. Another factor contributing to visible emissions is the nature of the hydrocarbons being combusted. Paraffins have the least tendency to smoke, whereas unsaturated and aromatic hydrocarbons have a higher tendency to smoke.

A flare must have the pilot burners on at all times to ensure ignition of the vent gas generated in the process system it serves whenever it is in operation. A stream of combustible gas, called purge gas, is continuously flowing into the flare to prevent air from entering the flare header which can create an unsafe explosive mixture of air and hydrocarbons. Depending on the flare design and size, the amount of purge gas needed to keep the flare safe varies considerably. Although the quantities are relatively small, the burning of pilot and purge gases represent a continuous source of emissions.

In a refinery setting, a gas flare may be installed for only one process area or it can be used to serve a number of process units for a wide variety of purposes ranging from controlling a small stream of leaks or vent gas from a piece of equipment to the disposal of large quantities of gases during an emergency. Therefore, depending on how a flare is designed and used, in Rule 1118 flares are classified into three distinctive categories: clean service, emergency service, and general service.

A clean service flare is used to only burn natural gas, hydrogen, liquefied petroleum gas, or other gases with a fixed composition vented from specific equipment. These gases contain little or no sulfur, and the quality (i.e., heat content and sulfur content) of the gas is usually predictable regardless of the flaring situations. In the basin, there are four clean flares, which are associated with three liquefied propane and butane storage areas and a hydrogen generating plant each.

An emergency service flare is a flare that receives vent gas only during emergencies. The quality and volume of the vent gases vary depending on the source and duration of the emergency release. Nevertheless, an emergency flare is usually in a standby mode and does not create emissions except for those associated with pilot and purge gases, and during actual emergencies.

The most common and complicated flare configuration is the general service flare. In addition to the services described above, flares in a refinery are also used to dispose of gases from routine or non-routine operations including purged gas streams, non-emergency releases of excess pressures, venting of storage tanks or wastewater sumps and equipment leaks, startups and shutdowns, turnaround activities, etc.

E. APPLICABLE RULES REVIEW

In addition to Rule 1118, flares are also subject to general AQMD prohibitory rules, such as Rule 401 – Visible Emissions, Rule 402 – Public Nuisance and Rule 431.1 – Sulfur Content of Gaseous Fuels. Flares built after June 11, 1973, are subject to 40CFR 60 Subpart J - New Source Performance Standards (NSPS); flares may also be subject to 40CFR 60.18 – General Control Device Requirements if either vent gases from storage tanks subject to 40CFR 60 Subpart Kb or from components subject to 40CFR 60 Subpart GGG are routed to them.

In order to maintain a smokeless operation, flares at refineries are equipped with steam jets (steam assisted) to provide good mixing of the flare gas with air. Within the smokeless range of operation of a flare, if not enough steam is used during a flaring event, smoking may occur due to pockets of incomplete combustion that are formed in the combustion zone. Rule 401 prohibits visible emissions in excess of Ringelmann 1 or 20 percent opacity for periods exceeding more than three aggregate minutes within any hour. 40CFR 60.18 requires flares to have no visible emissions except for periods of time up to five minutes during two consecutive hours. The two standards are not identical, since they use different methods to determine visible emissions: Rule 401 uses USEPA Reference Method 9 and 40CFR 60.18 uses USEPA Reference Method 22.

If combustion is incomplete, as denoted by visible emissions, odorous materials may be emitted, affecting the area downwind of the flare and potentially resulting in a public nuisance. Odors could also be emitted if the heat content of the flared gas is very low resulting in the flame temperature not being hot enough to ensure complete destruction of odorous materials. The flare operator should supplement combustion with high BTU content gas to prevent this problem. A steam- or air-assisted flare should not be used for disposal of gases with less than 300 BTU/scf.

Although flares operate within refineries subject to Regulation XX - RECLAIM, they are not included in this program and their emissions do not count towards refineries' RECLAIM SOx and NOx allocations. The total sulfur content of the flare pilot gas and the purge gas, which maintain the flare operating continuously, is limited to a concentration of 40 ppm calculated as H_2S, averaged over a four hour period per Rule 431.1 – Sulfur Content of Gaseous Fuels. Most of the flares in the basin use natural gas for purge and pilots in order to comply with this requirement. The total sulfur content of the vent gas routed to a flare due to an emergency is exempt from the rule requirements. The federal regulation, 40CFR 60 Subpart J, has a limit of 160 ppm H_2S, averaged over a rolling three hour period, for purge and pilot gas combusted in a flare, whereas emergency vent gases and relief valve leakage are exempt from this requirement.

F. AFFECTED FACILITIES

The types of refinery operations subject to this rule are: petroleum refineries, sulfur recovery plants that recover sulfur compounds from acid gases and sour water generated by petroleum refineries, and hydrogen production plants that produce hydrogen from refinery gas and supply it for petroleum refinery operations. Presently, in the AQMD, there are seven operating petroleum refineries, one sulfur recovery plant and one hydrogen production plant, with a total of 10 distinct physical locations. The following facilities operate 27 flares subject to Rule 1118:

- Air Products (Hydrogen Production Plant)
- BP West Coast Products (Refinery)
- Chevron Products Company (Refinery)
- ConocoPhillips Company (Refinery – Carson Plant)
- ConocoPhillips Company (Refinery – Wilmington Plant)
- Equilon Enterprises, LLC, Shell Oil Products US (Los Angeles Refinery)
- Equilon Enterprises, LLC, Shell Oil Products US (Sulfur Recovery Plant)
- ExxonMobil Oil Corporation (Refinery)
- Paramount Petroleum Corporation (Refinery)
- Ultramar Inc. (Refinery)

Table I-1 shows the subject facilities and an inventory of their flares. Since ConocoPhillips and Equilon Shell Oil submit one quarterly Rule 1118 report for both their facilities (Carson

Plant/Wilmington Plant and L.A. Plant/SRU, respectively) the table shows eight reporting facilities.

Table I -1
Flare Inventory

Reporting Facility	Number of Flares	Type of flare	Type of Service	
			Clean	Emergency/ General Service
A	4	Elevated	1	3
B	1	Ground Flare	1	
C	2	Elevated		2
D	2	Elevated	1	1
E	5	Elevated		5
F	1	Elevated		1
G	6	Elevated		6
H	6	Elevated	1	5
8 Facilities	**27 Flares**		**4**	**23**

C H A P T E R II

CONTROL TECHNOLOGY

A. CONTROL OPTIONS

At petroleum refineries, flares have historically been used to dispose of combustible gases resulting from emergency relief, overpressure, process upsets, startups, shutdowns and other operational and safety reasons to prevent direct release of toxic and /or odorous substances to the atmosphere. In recent years, U.S. Occupational Safety and Health Administration (OSHA) and U.S. EPA have become more concerned with refinery operation, resulting in tighter regulations on safety and emissions control and enforcement actions such as Consent Decrees, as shown before. Furthermore, smoke, noise, glare and odors sometimes associated with refinery operations may, and at times have impacted the surrounding communities, leading to an increase in the involvement of community and environmental groups in the regulatory process of controlling refinery flares.

There are two alternatives to control flare emissions: post-combustion and pre-combustion controls. Possible post-combustion controls could be selective catalytic reduction (SCR) units, Lo-NOx burners, scrubbers and bag houses. While post-combustion control technology exists, the unpredictability of the flare operation and the fact that combustion takes place at the tip of an flare 150 to 200 feet above the ground make such control devices impractical for elevated flares.

Controlling flue gases would be very costly under these circumstances and results would not be guaranteed. Therefore, the best way to control and minimize flare emissions is through the use of pre-combustion control, which prevents the formation and reduces the amount of vent gases routed to refinery flares, or recover the vent gases prior to combustion at the flare.

B. FLARE MINIMIZATION PLANS

Refineries can obtain meaningful results in their effort to minimize the volume of vent gases routed to the flare by setting up and implementing flare minimization plans. It is possible to achieve significant reductions in the volume of vent gas generated by process units at refineries. Listed below are several possible alternatives of minimizing flare emissions that could be incorporated in flare minimization plans:

- <u>Better engineering and equipment design</u>
  A reevaluation of existing process flow and equipment allowing changes in operating parameters such as temperature and pressure settings may result in reduced volumes of vent gas being generated.

- <u>Diverting or eliminating streams vented to the flares</u>
  Certain streams that routinely are directed to the flare may be rerouted and either treated for use as fuel gas or recycled back in the process.

- <u>Installation of redundant equipment to increase reliability</u>
  By installing redundant equipment, in case of a breakdown, the spare can be put on line, thus avoiding a process upset that results in gas being routed to the flare.

- <u>Installation of flow monitors for vent gas generated at each process unit</u>
  Installation of flow monitors on process units flare headers is a useful tool that allows the operator to quickly identify the origin of increased flare flows and take immediate corrective actions, potentially avoiding a flare event.

- Periodic monitoring maintenance programs of pressure relief valves that identify leaks to the blowdown system, such as acoustic or thermal surveys
  Pressure relief devices may develop leaks in time, due to the corrosive nature of the process, due to chattering or improper reseating. Given the extended periods of time between turnarounds, leaks may result in significant emissions, even at small rates. By conducting acoustical or thermal surveys of relief devices connected to the flare, the operators can identify and, with detection equipment currently available, even quantify the amount of leak-through gas that escapes to the flare. Upon identification of leaking relief devices, the operator can prioritize their maintenance and repair in order to reduce flare emissions. This program is especially valuable for those flares that are not equipped with flare gas recovery because these leaks end up being combusted in the flare for extended periods of time until the next scheduled turnaround.

- Conducting Specific Cause Analysis of significant flaring incidents
  This investigative procedure is used to identify the cause of significant flaring events and whether any equipment and/or operational changes are needed to prevent future reoccurrences. Once the investigation is completed, corrective measures need to be taken and implemented. It is important to communicate the findings to all parties involved and create a mechanism to track corrective actions in order to prevent future events. This analytical process enables a facility to shift the focus on preventing flaring events rather than reacting to them.

- Operator training for environmental awareness
  Making the operators aware of the impact of flare events on the environment and teaching them procedures that minimize venting to flares needs to be part of the facility's training program and should have full management support.

- Optimization of turnaround schedules
  Coordination of turnaround schedules for different units can result in reducing flaring activity and minimize emissions associated with these periodic maintenance activities.

- Developing startup and shutdown procedures that do not use flaring
  For certain units, it is possible to develop procedures that avoid flaring during shutdown and startup, such as using reduced loads, recycling feeds, better decontamination procedures, etc. Sometimes more time is necessary for a startup or shutdown, or physical modifications achieve this purpose.

C. FLARE GAS RECOVERY SYSTEMS

An alternative control option to minimizing the volume of vent gases routed to flares is to simply prevent the vent gases from being combusted in the flare by recovering them with a flare gas recovery system. In light of increasing environmental concerns, this flare gas recovery system control option is becoming popular, especially since there is an economic incentive due to recovery of valuable gas. The system usually consists of a set of compressors, a heat exchanger, a phase separator and associated pumps. The vent gas is compressed, cooled and routed to an amine scrubber for removal of sulfur compounds, and subsequently may be used as fuel gas or feed for refinery processes. A flare system generally consists of a header or manifold that collects the flare gases from various sources, a knockout drum, a liquid seal (usually water) drum, and the flare itself. A flare gas recovery system unit connection is typically located between the knockout vessel and the flare water seal.

The primary control variable of the flare gas recovery system is the flare system pressure. As vent gases from various process units collect in the flare header, pressure reaches a predetermined pressure control set point, triggering the start up of the recovery compressor. The suction pressure of the compressor is set lower than that of the water seal, such that under normal operation, there is not enough pressure in the flare header to break through the liquid seal and all gas is recovered. During major upsets, if the flow exceeds the compressor capacity, the flare header pressure increases, breaking the liquid seal and the vent gases reach the flare, where they are combusted. Therefore, the safety function of the flare system is maintained in the event of process upset conditions.

In order to have a high recovery rate, the compressor station should be sized with a capacity two to three times the normal flare flow (Oil and Gas Journal, December 7, 1992). API Guideline 520 states that the normal flow rate is some average flare load or a frequently encountered maximum load and that the recovery system should be designed to operate over a wide range of dynamically changing loads. API 520 goes on to say that often these systems are installed to comply with local regulatory limits and therefore, must be sized to conform to any such limits.

CHAPTER III

PROPOSED RULE AMENDMENTS

PROPOSED AMENDMENTS

Staff proposes amending Rule 1118 as follows:

- Add, modify or delete definitions.
- Add new operational requirements for flares and establish diagnostic practices to minimize flaring.
- Prohibit the flaring of gases other than those resulting from emergencies, shutdowns, startups, turnarounds and essential operational needs and require minimization of such flaring.
- Establish refinery specific performance targets for minimizing flare emissions based on annual crude throughput.
- Require refineries to pay a mitigation fee for exceedances of a refinery specific performance target.
- Require a Flare Minimization Plan and possible issuance of a Notice of Sulfur Dioxide Exceedance when flare SOx emissions exceed the facility specific target for a given year.
- Add and modify requirements for the Flare Monitoring and Recording Plan.
- Add and modify requirements for the operation monitoring and recording.
- Modify the recordkeeping requirements.
- Add new notification and reporting requirements.
- Expand and update the test methods.
- Modify and add exemptions.
- Enhance and update monitoring specifications in Attachment A – Flare Monitoring System Requirements.
- Modify and enhance Attachment B – Guidelines for Calculating Flare Emissions which include missing data substitution procedures.

A. DEFINITIONS

The following definitions are new:

- Emergency - is defined as a condition that requires immediate attention to restore normal operation, caused by a sudden, infrequent and unavoidable event. An emergency may be caused by equipment breakdown, natural disaster or an act of war or terrorism. If a repetitive flare event from the same equipment is caused by poor maintenance or a flare event results from careless operation, it will not be deemed an emergency.
- Essential Operational Need – is defined as flare event caused by a specifically listed operational or maintenance related activity where due its quality or quantity, the vent gas cannot be reasonably recovered, treated, used or delivered for sale with existing equipment. Examples of Essential Operational needs as determined by the Executive Officer are:

  Temporary fuel gas imbalances caused by inability of a customer to receive sales gas used for generation of electricity for a state grid or a third party contractual gas purchase agreement, or due to sudden shutdown of a combustion device for reasons other than operator error or poor maintenance;

Leakage of relief valves due to malfunction;

Venting of gas streams that are incompatible with the operation of the flare gas recovery equipment (e.g., molecular weight outside the design range) or that could pose a safety hazard to the fuel gas system (e.g., very low or very high BTU content that causes temperature swings in combustion devices, upsetting the process). Whenever the vent gas has a low BTU content a refinery may use supplemental natural gas or other clean gas that is compliant with Rule 431.1 to ensure high combustion efficiency;

Venting of clean gas streams to either a clean service flare or a general service flare;

Intermittent minor venting from sight glasses, compressor bottles, sampling equipment and pumps or compressors casings;

Emergency situations when the pressure vessel operati~~o~~ng pressure rises above the set point of the pressure relief ~~valve~~device(s).

- Flare Gas Recovery System - is defined as any system designed to prevent or minimize the combustion of vent gases in a flare, composed of, but not limited to, compressors, heat exchangers, pumps, water seal drums, etc.
- Flare Minimization Plan is defined as a document that meets specific rule requirements in subdivision (e).
- Natural Gas - is defined as 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.
- Notice Of Sulfur Dioxide Exceedance – is defined as a notice that may be issued by the Executive Officer to a refinery in the event an annual performance target is exceeded and remains in its compliance record.
- Pilot - is defined as an auxiliary burner used to ignite the vent gas routed to a flare.
- Purge Gas - is defined as a continuous gas stream introduced in the flare header, flare stack and /or flare tip for the purpose of maintaining a positive flow that prevents that prevents the formation of an explosive mixture due to ambient air ingress.
- Sampling Flare Event – this definition replaces Recordable Flare Event and applies to flare events with a flow rate of at least 330 scfm for fifteen consecutive minutes or more, or any other flare event as approved in writing by the Executive Officer upon request from a facility, due to specific operational parameters of a flare. 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.
- Shutdown - is defined as the procedure by which the operation of a process unit or piece of equipment is stopped at the end of a production run or for the purpose of performing maintenance, repair or replacement of equipment.
- Specific Cause Analysis - is defined as an investigation used to identify the cause of certain flare events with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of flared gas, provide corrective measure(s), and prevent recurrence of a similar event.

- Startup - is defined as the procedure by which a process unit or piece of equipment achieves operational status. The attainment of normal operational status may be substantiated by parameters such as temperature, pressure, feed rate and also by products meeting quality specifications.
- Turnaround - is defined as a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair, replacement of equipment, or installation of new equipment.
- VOC – is defined as in Rule 102 of AQMD Rules and Regulations.

The following definitions were modified:

- Flare Event - clarifies that an event takes place when vent gas is combusted in a flare and ends when the vent gas velocity drops below 0.12 feet per second, or when no more vent gas is combusted as demonstrated by the water seal monitoring record or other parameters as approved by the Executive Officer in the Flare Monitoring and recording Plan.
- Flare Monitoring System - was expanded to include, in addition to the flow meter, a continuous higher heating value analyzer and a total sulfur analyzer.
- Gas Flare - was shortened by removing “Gas” since this rule addresses flares used to dispose of gases only.
- Hydrogen Plant - was expanded to include the processes used to generate hydrogen.
- Representative Sample - was modified by deleting part of the definition that no longer applies or was moved under monitoring requirements.
- Petroleum Refinery – was expanded, for the purpose of this rule, to clarify that all portions of the petroleum refining operation, including those at non-contiguous locations operating flares, shall be considered as one petroleum refinery.
- Sulfur Recovery Plant - was expanded to also include sour gases as process feed.
- Vent Gas - was redefined as any gas generated at a refinery that is routed to a flare excluding assisted air or steam injected directly into the stack or flare combustion zone via a line separate from the flare header.

The following definition was deleted:

- Recordable Flare Event - was removed due to the new monitoring requirements and was replaced with “sampling flare event”.

B. REQUIREMENTS

Staff has added new requirements for flares, arranged by the date they become effective.

The following requirements become effective on January 1, 2006:

- A flare must have the pilot flames present any time the system it serves is in operation.
- All flares must operate without visible emissions, as determined by US EPA Method 22. The method allows for visible emissions for no longer than five minutes within a two consecutive hour period.

- All pressure relief devices (PRDs) connected directly to flares must have an annual inspection using acoustical or thermal surveys in order to detect leaks. The requirement applies only to PRDs venting directly to flares (gases that are not collected or controlled with flare gas recovery and treatment. The inspection has to be conducted within 90 days prior to a scheduled turnaround, if one is scheduled for that calendar year.
- The owner or operator of a flare having a flaring event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of vent gas combusted is required to conduct a Specific Cause Analysis of the event. Flare events associated with planned shutdowns, planned startups, and turnarounds are exempt from this requirement since their cause is known and therefore no investigation is necessary.
- The owner or operator of a flare has to identify the cause, where feasible, of any flare event where at least 5,000 standard cubic feet of vent gas was released to the flare. For some smaller releases, the owner or operator may not have sufficient data to determine the cause of the flare event.

The following requirements are effective ~~January~~ September 1, 200~~7~~6:

- The owner or operator of a refinery subject to rule shall submit the technical detail of each flare system, including an audit of vent gas recovery capacity, an assessment of the flare gas reductions achieved since the adoption of Rule 1118 in 1998 and the planned future flare emission reductions.

The following requirements are effective January 1, 2007:

- The owner or operator of a refinery subject to this rule shall submit an evaluation of options to reduce flaring during planned events such as shutdowns, startups and turnarounds. The evaluation shall include, but is not limited to such options as slowing the depressurization of vessels, storing vent gases, etc.
- Owners or operators have to operate flares such that only vent gases resulting from an emergency, shutdown, startup, turnaround or essential operational need are combusted and have to minimize flare emissions during these events.
- Staff acknowledges that some refineries will install gas recovery and treatment system(s) to comply with this requirement, and that the refineries will need time to connect and operate these systems. In recognition of this need staff proposes to establish a compliance date of no later than January 1, 2009, or January 1, 2010 if more than two flares are to be controlled, provided that those refinery operators submit an application to construct and operate the control equipment for approval by the Executive Officer prior to January 1, 2007.

The following requirement is effective on January 1, 2009:

- Any vent gas combusted in a flare, except for vent gas resulting from an emergency, shutdown, startup, process upset or relief valve leakage, cannot exceed 160 ppm H_2S concentration, averaged over three hours. Staff believes that by January 1, 2009, most refineries will have sufficient vent gas recovery and treatment capacity to be able to comply with this requirement during essential operational needs, for which this requirement would essentially apply. Refineries needing to install gas recovery and treatment system(s) for more than two flares to comply with the requirements to limit and minimize flaring under paragraph (c)(3), as well as this requirement to limit the H_2S concentration in the vent gas, will be granted a compliance date of January 1, 2010, to be consistent with the requirements of paragraph (c)(3), provided that those refinery operators submit an application to construct and operate the control equipment for approval by the Executive Officer prior to January 1, 2007.

C. PERFORMANCE TARGETS

PAR 1118 prohibits flaring of gases other than those resulting from emergencies, shutdowns, startups, turnarounds, and essential operational needs. It also sets decreasing flare total sulfur performance targets for the allowed flaring activities, calculated and reported as sulfur dioxide (SO_2), for subject refineries, based on 2004 ~~throughputs~~crude processing capacities, with the purpose of capturing emission reductions achieved since the rule was adopted and to ensure that these and future emission reductions are enforceable, permanent, real, and verifiable. During the rule development process, industry identified an inequity of using crude throughput versus crude capacity based on a fixed year of 2004 to establish annual SO_2 performance targets. In any one year, any refinery could be conducting a shutdown or turnaround of a major crude processing unit, which could reduce crude throughput for that baseline year reflecting an artificially low baseline throughput for that refinery. Whereas crude processing capacity more accurately allocates refinery emissions based on normal refinery operations. Local refineries are operating at near capacity; therefore, the difference in emissions impact and reductions based on throughput or capacity are minimal. Total SO_2 reductions will be determined annually for each calendar year. To determine compliance with the SO_2 Performance Targets, the annual emissions will be divided by the 2004 refinery ~~throughput~~crude processing capacity. The performance targets proposed and the corresponding milestones, starting with year 2006, are as shown in Table III - 1:

Table III– 1
SO_2 Performance Targets
(Tons per million barrels crude process~~ed~~ing capacity)

Year	2006	2008	2010	2012
SO_2 Performance Target	1.5	1	0.7	0.5

In the event that a refinery exceeds the specified performance target in any calendar year, it will have to pay a mitigation fee for each ton of sulfur dioxide over the limit based on the following levels of exceedance: $25,000 for each and every ton where the exceedance is up to ten percent over the performance target, $50,000 for each and every ton where the exceedance is greater than ten percent but no more than twenty percent over the annual performance target, or $100,000 for each and every ton where the exceedance is greater than twenty percent over the applicable performance target. The mitigation cannot exceed $4,000,000 dollars per each petroleum refinery in any one year. Any mitigation fees paid would be used to implement emission reduction projects in the area impacted by the excess emissions.

It is expected that refineries will implement the procedures and install the equipment necessary to achieve compliance with the annual sulfur dioxide performance targets. However, since the operation of flares is variable based upon periodic events, some of which may be unforeseeable, it is possible that a refinery could exceed a performance target in any one year. The mitigation fee provision offers the refinery an alternative compliance option in that circumstance and allows the opportunity for the refinery to take those actions necessary to ensure the performance targets are met in future years. For each year an annual performance target is exceeded, the Executive Officer may also issue a Notice of Sulfur Dioxide Exceedance that will become part of the petroleum refinery's compliance record.

In establishing the appropriate monetary amount for the mitigation fees, staff considered two larger petroleum refineries that currently have no or limited controls on their flares. Historical flare sulfur dioxide (SO_2) emissions and flare vent gas flows for the two facilities for the years 2002, 2003 and 2004 and the three year average are shown in Table III - 2.

Table III – 2

Historical Data

		2002	**2003**	**2004**	**Average**
Refinery 1	**SO_2 (tons/year)**	59	76	27	54
	Flow (million cubic feet per year)	804	804	657	755
Refinery 2	**SO_2 (tons/year)**	77	45	19	47
	Flow (million cubic feet per year)	308	324	289	307

As part of their 2004 Emissions Fee Billing (EFB) submittal, .Refinery 1 and Refinery 2 reported processing of approximately 95 and 51, million barrels of crude oil during the 2003-2004 fiscal year, respectively. Table III-3 is a summary of the permitted annual crude oil throughput (in million barrels of crude oil per year), the 201~~0~~2 performance target for each petroleum refinery target (in tons SO_2) and the amount of SO_2 exceedance at twenty percent over the 2012 annual SO_2 performance target of 0.5 tons per million barrels of crude oil.

Table III – 3
Analysis

Facility	**Annual Crude Oil Throughput (million barrels)**	**201~~0~~2 Annual SO_2 Performance Target (tons)**	**20% SO_2 Exceedance (tons)**
Refinery 1	93	47	10
Refinery 2	50	25	5

To estimate the vent gas flow associated with the 10 tons and 5 tons of sulfur dioxide excess emissions, staff will use the ratio of three year average of vent gas flow to SO2 emissions. Staff believes that the total flow and SO2 emissions for any year will average the high and low flows and SO2 emissions that will be used to determine the approximate vent gas flow for the sulfur dioxide excess emissions.

Therefore, the flow associated with the yearly exceedance, in million standard cubic feet per year (mmscfy) and calculated as daily, averaged over 365 days (mmscfd) is:

Refinery 1

$Flow_1$ = 10 tons * 755 mmscfy / 54 tons = 140 mmscfy = 0.38 mmscfd

Refinery 2:

$Flow_2$ = 5 tons * 307 mmscfy / 47 tons = 33 mmscfy = 0.09 mmscfd

To prevent future exceedances, it is assumed that the two facilities would have to install flare gas recovery and treating systems to control this amount of vent gas associated with the SO_2 exceedance. The capacity of the control system should be two to three times the vent gas flow rate; staff has determined the cost of a flare gas recovery and treating system to be $2.17 million per million standard cubic feet per day (mmscfd) of vent gas recovery/treatment (see discussion in Chapter VI).

The cost to install vent gas recovery and treatment to control the incremental amount of sulfur dioxide that caused the exceedance of the annual performance target is:

Refinery 1

Control Cost = 0.38 mmscfd * 2 * $2.17 million per mmscfd / 10 tons per day

= $164,920 per ton SO_2 reduced

Refinery 2

Control Cost = 0.09 mmscfd * 2 * $2.17 million per mmscfd / 5 tons per day

= $78,120 per ton SO_2 reduced

The average cost to control the incremental amount of sulfur dioxide that caused the exceedance of the annual performance target is $121,520. As previously stated, the operation of flares and resultant emissions are variable based upon periodic events. Therefore, a mitigation fee of $100,000 per ton of SO_2 for annual exceedances of more than twenty percent of the annual performance target is appropriate. The mitigation fee for exceedances less than twenty percent are less than the cost of vent gas recovery and treatment and therefore would be considered reasonable.

D. FLARE MINIMIZATION PLAN REQUIREMENTS

Each refinery that exceeds an annual performance target must submit a Flare Minimization Plan to the AQMD for approval from the Executive Officer, along with appropriate fees pursuant to Rule 306 but no later than 90 days from the end of the calendar year when the performance target was exceeded that demonstrates the actions to be taken to achieve the performance targets. The main required elements of the plan are:

- A complete description and technical specifications for each flare at a facility;
- Detailed process flow diagrams of upstream equipment venting to each flare and an identification of all control equipment;

- Policies and procedures, as well as any additional equipment, to be used to minimize vent gases during emergencies, shutdowns, startups and turnarounds and during essential operational needs; and
- A complete description of a flare gas recover and treatment system(s) to be installed to meet the performance target(s).

The AQMD will make available the Flare Mininimization Plans, less any confidential information, for public comments for a period of 60 days and respond to them prior to taking action on the plans. Any facility that exceeds it annual sulfur dioxide emission limit during a subsequent calendar year will have to submit to the AQMD a revised Flare Minimization Plan within 90 days from the end of the calendar year, in which it will detail additional measures for preventing future exceedance. If the Executive Officer deems the plan deficient, the facility has 45 days to correct and resubmit it. Failure to do so would cause the Executive Officer to deny the plan and issue the facility a Notice of Violation.

A facility may, without exceeding the performance targets and on a voluntary basis, submit a Flare Minimization Plan for approval to the Executive Officer. The plan would be subject to the same provisions as a mandatory plan, but if denied no Notice of Violation would be issued to the facility.

E. FLARE MONITORING AND RECORDING PLANS

Each existing facility currently in operation must submit a revised Flare Monitoring and Recording Plan by June 30, 2006 for approval by the AQMD, along with appropriate fees pursuant to Rule 306. Any new facility or non-operating facility that starts operating after the rule is amended will have to submit a Flare Monitoring and Recording Plan and appropriate fees at least 180 days prior to initial start-up and notify the AQMD seven days prior to startup or resumption of operations. The current monitoring plans submitted pursuant to Rule 1118, adopted February 13, 1998 will be in effect until the revised plans are approved by the AQMD. The revised plans must provide, in addition to the existing information, details on installed heat content analyzers, total sulfur analyzers and upgraded flow meters, where applicable.

F. OPERATION MONITORING AND RECORDING

The proposed amendment has several new requirements for flare monitoring and recording. The new requirements will be phased in as follows:

Effective ~~upon rule amendment~~January 1, 2006:

- The presence of a flare pilot flame has to be monitored using a thermocouple or an equivalent device, such as infrared or ultraviolet cameras.
- ~~Refineries will have to use video monitors equipped with date and time stamp to monitor the flares for visible emissions. The video recording will have to be maintained at the facility for a period of 90 days and submitted to AQMD personnel upon request.~~

~~Effective January 1, 2006:~~

- Facilities subject to this rule are required to take a daily representative sample. Only one representative sample is required each day for flare events that are not sampling flare events. A representative sample collected for a sampling flare event on that day may be used to satisfy this requirement. For flare events lasting 15 minutes or less, no representative sample is required. A sample shall not be required if the operator demonstrates vent gas is not routed to a flare based on 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.

Effective July 1, 2006:

- Refineries will have to use video monitors equipped with date and time stamp to monitor the flares for visible emissions. The video recording will have to be maintained at the facility for a period of 90 days and submitted to AQMD personnel upon request.

Within six months from approval of the Flare Monitoring and Recording Plan, but no later than July 1, 2007:

- Continuous higher heating value and semi-continuous total sulfur analyzers are required for emergency and general service flares to eliminate problems related to sampling and data accuracy, as recommended in the Evaluation Report on Emissions from Flaring Operations at Refineries. The use of analyzers will provide a more realistic picture of flare emissions by providing more data points for the heat content and total sulfur content of the vent gases, thus increasing the accuracy and reliability of emission reporting, that is currently achieved by using data from weekly samples. Refineries must begin monitoring within six months from approval of the Revised Flare Monitoring and Recording Plan by the AQMD. Until the analyzers are installed and certified by the Executive Officer, the refineries will be required to measure and sample for both higher heating value and total sulfur daily (an increase from the current weekly sampling requirement) in addition to collecting representative samples during a sampling flare event, using a step by step procedure outlined in Table ~~2~~1 (Effective Until June 30, 2007), footnote 4 of the proposed amended rule. However, if no flare event takes place during the day, as demonstrated by water seal level records or other parameters as approved in the Flare Monitoring and Recording Plan, no sample is required. In the event that samples cannot be taken due to an exempt occurrence and emissions are estimated, the methods are those in the missing data procedures included in an appendix to the rule and estimated emissions have to be reported as such in the quarterly flare report.

Effective January 1, 2007:

- Flow meters are required for monitoring and recording the purge gas and pilot gas flow rates for all emergency and general service flares and have to be approved by the AQMD.
- All emergency and general service flare flow meters will have to be installed at a representative location to indicate an accurate flow to the flare. This requirement was necessary since there are flow meters located upstream of water seals at flares equipped with flare gas recovery systems that may indicate a flow that actually is recovered and not breaking the water seal. The operators monitor the water seal level to determine whether an actual flare event took place. There are also problems at low flows, when ambient heat creates a gas flow inside the large diameter flare headers, resulting in a "ghost" reading on the flow meter. In order to eliminate these problems, flow meters have to be installed downstream of water seals or, if this is not feasible due to physical

constraints, they need to be equipped with totalizing capability that discounts reverse flows to a recovery compressor or due to turbulence created by ambient heat.

- Each emergency and general service flare that is not equipped with a total sulfur analyzer will have to be equipped with an automated sampling system capable of alerting the operator that a sampling event has started.

G. RECORDKEEPING REQUIREMENTS

The proposed amendment requires that video recordings of all flares be kept for 90 days and all other records mandated by the rule be kept for a period of five years.

H. NOTIFICATION AND REPORTING

The proposed amendment has new notification requirements and enhanced reporting requirements, as follows:

- Facilities subject to this rule will have to 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.

- Refineries will have to notify the AQMD by telephone within one hour of a flare event exceeding 100 pounds of VOC, 500 pounds of total sulfur emissions calculated as sulfur dioxide, or 500,000 standard cubic feet of vent gas. The one hour time requirement starts at the time the refinery operator facility knows or should have known that the aforementioned mass levels may have been emitted or the vent gas as measured by the flow meter is determined to exceed 500,000 standard cubic feet of vent gas. A "specific cause analysis", identifying the cause and duration of the event, mitigation and corrective actions taken, has to be submitted to the AQMD within 30 days.
- A 24-hour advance notice to the AQMD is required for scheduled planned flare events that have the potential to exceed 100 pounds of VOC or 500 pounds of total sulfur, calculated as sulfur dioxide or 500,000 standard cubic feet of vent gas.
- The quarterly reports will have to be submitted in an electronic format approved by the AQMD and certified in writing by a responsible facility official that the information is true and accurate. Emissions will have to be calculated or, in case of missing data, substituted using the guidelines in Attachment B to the rule. The refineries will also have to include in the quarterly report a categorization of flare events by cause and the associated emissions. Lastly, records of leak surveys done in the quarter for pressure relief devices connected to flares will have to be reported, including identification of the devices, dates of inspection and the person(s) conducting the surveys.

I. TEST METHODS

The following are additions and modifications to this section of the rule:

- The higher heating value of the flare vent gas has to be monitored with a semi-continuous analyzer meeting or exceeding the specifications in Attachment A to the rule.
- Total sulfur concentration calculated as sulfur dioxide may be monitored with a semi-continuous total sulfur analyzer meeting or exceeding the requirements in Attachment A

to the rule. Until such time as the monitor is certified by the Executive Officer, the samples collected by the refinery operator shall be determined using AQMD Method 307-91 or updated ASTM Method 5504-01.

- The accuracy of the flare flow meters has to be verified annually according to manufacturer's procedures.
- For determining visible emissions from flares, refineries have to use procedures outlined in U.S. EPA Method 22, 40CFR Part 60 Appendix A.

J. EXEMPTIONS

An exemption was added for excluding the flare-related total sulfur emissions, calculated as sulfur dioxide, resulting from external power curtailments excluding interruptible service agreements, natural disasters and acts of war or terrorism, from the annual facility emissions established under Performance Targets since these events are beyond the reasonable control of the refinery operator. In addition, has added language to clarifying that sampling and analyses of representative samples for higher heating values and the concentration of total sulfur, expressed as sulfur dioxide, pursuant to paragraph (g)(3) may not be required for any flare event when collecting a sample is unfeasible or constitutes a safety hazard

K. ATTACHMENT A

Attachment A was enhanced by incorporating additional specifications for the continuous flow measuring device and adding new specifications for the heat content analyzer and the total sulfur analyzer.

L. ATTACHMENT B – GUIDELINES FOR CALCULATING FLARE EMISSIONS

Attachment B was modified to include equations and emission factors for calculating flare emissions for vent gas, natural gas, propane and butane, thus making reporting uniform among refineries, sulfur recovery plants and hydrogen production plants. Another addition provides the methodology to be used for data substitution during flow meter, sampling and analyzer down periods or when the representative samples are not measured and recorded pursuant to the rule requirements. Data substitution is not required if it can be demonstrated to the satisfaction of the Executive Officer that there was no flow to the flare during the flow meter and/or analyzer outage or a sample was not taken and analyzed. Footnote 4 in Table 1 of Rule 1118 further explains that samples specified in Table 1 will not be required if the operator demonstrates that vent gas is not being routed to a flare based on 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 Revised Flare Monitoring and Recording Plan.

Once the methodology and parameters used to demonstrate that the vent gas is not being routed to a flare is included in the approved Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan, it is considered to be to the satisfaction of the Executive Officer for the purpose of making the above demonstration. If there was flow, the method shown in equation (1) shall be used to calculate the substituted data, unless an alternate method using recorded and verifiable operational parameters and/or process data is approved by the Executive Officer to be representative of the missing parameters, including reference to similar events that occurred previously. The goal of the data substitution methodology was to provide a conservative estimate based on the operational history of the flare.

$$MP = P_{Max} - 0.5 \times \left(P_{Max} - P_{Avg} \right) \qquad \text{Equation (1)}$$

where:

MP = The missing parameter for which data was not recorded.

P_{Max} = Maximum measured and recorded value of the missing parameter over a 5 year period.

P_{Avg} = Average measured and recorded value of the missing parameter over a 5 year period.

This methodology was developed based on the reported flare event data for refineries operating in the South Coast Air Basin (including a sulfur plant) between October 1, 1999 through June 30, 2005. The data reported by the refineries and utilized in the analysis included:

- The duration of each individual flare event;
- The total volume of gas released during the flare event;
- The higher heating value of the flared gas;
- Basis for which the higher heating value (HHV) of the flared gas was determined (lab measurement, average of previous events, etc.);
- The sulfur content of the flared gas; and
- Basis for which the concentration of total sulfur, expressed as sulfur dioxide, of the flared gas was determined (lab measurement, average of previous events, etc.).

Data whose origin was not based on a discrete measurement was discarded. It was discarded so the entirety of the data being analyzed would be representative of actual flare events. This would prevent variability in the data being attenuated through the introduction of substitute data based on an average.

The data for each recorded flare event between October 1999 and June 2005 for each flare were plotted as a function of time. These plots revealed:

- The concentration of total sulfur, expressed as sulfur dioxide, in the flared gas showed a high degree of data scatter that varied randomly over a potential range of 200,000 ppm.
- The volume of gas flared in terms of rate and total volume released showed a high degree of data scatter which varied randomly over a potential range of 39,000 MSCF.
- The HHV of the flared gas exhibited the lowest degree of data scatter, but still varied randomly. The magnitude of the variation was over a potential range of 5000 Btu/scf.

The large range and randomness exhibited by the population of data posed the following difficulties in creating a methodology for estimating substitute data:

- Requiring the facility to report substitute data based on the single highest historical measured value would result in the facility grossly over-estimating their emissions. The emission would be grossly over-estimated as a result of the majority of the flares having a single point outlier for each data set that was orders of magnitude greater that the majority of the population.
- Requiring the facility to report an average value would result in a significant portion of the data falling above the mean value. There would be a large portion of data above the mean value due to the high degree of data scatter exhibited by the population of data.
- A methodology based on a short term sample of data could result in substitute data being under-estimated. The data would be under-estimated if the short term sample happened to be taken from a period where the values of the short term population were on a down-trend. There were flares in the analyzed data set, which included 23 consecutive quarters (5 years, 9 months) of reported data that demonstrated cyclic behavior. Coincidently, the refineries have stated that they turnaround their units every five years. This behavior showed surges in the value of a given parameter, followed by a lull. Any data that were estimated based on the lull period would provide under-estimated results during the surge, which is contrary to the goal of the substitution methodology.

The method shown in Equation (1) accounted for the problems listed above. This method accounts for the average value of the population with respect to the deviation from the mean. The use of a five year (20 quarters) averaging period also eliminates the potential of under-estimating substitute data due to basing it's value on a short term period where the value of the population could be in a lull. The 0.5 multiplier in equation (1) was empirically determined by fitting the equation to the population of data. The equation was fit multiple times with the multiplier incrementally increased between a range of 0.4 and 0.7. The 0.5 multiplier provided the desired result. This value provided a result that generally captured 98% of the population of data, but was sufficiently less than the single point outliers that were present in some populations of data.

CHAPTER IV

EMISSION INVENTORY

A. CONTRIBUTING SOURCES

As shown in Chapter I, in the AQMD there are seven petroleum refineries, one sulfur plant and one hydrogen generating plant accounting for 27 flares categorized as emergency flares, clean flares and general purpose flares. The breakdown by flare, as reported in the September 2004 Evaluation Report, including flare system design and flare gas recovery capacities, is shown below in Table IV – 1.

Table IV – 1
Flare Inventory

Flare ID	Capacity (lbs/hr)	Vapor Recovery Capacity (MMscfd)	Notes
Flare No. 1	41,000	0.36	
Flare No. 2	232,281	6.96*	
Flare No. 3	1,120,000	1.4*	
Flare No. 4	600,000	None	
Flare No. 5	343,900	None	Clean Flare
Flare No. 6	1,300,000	2	
Flare No. 7	250,000	None	
Flare No. 8	1,040,000	4.8	
Flare No. 9	956,000	None	
Flare No. 10	133,950	6.96*	
Flare No. 11	825,000	None	
Flare No. 12	6,000	None	Clean Flare
Flare No. 13	1,300,000	6	
Flare No. 14	26,718	None	Clean Flare
Flare No. 15	3,540,000	9.8	
Flare No. 16	176,000	None	
Flare No. 17	960,000	6	
Flare No. 18	1,400,000	6	
Flare No. 19	173,000	None	
Flare No. 20	188,000	None	
Flare No. 21	1,220,000	1.25	
Flare No. 22	655,000	1.4*	
Flare No. 23	26,000	None	
Flare No. 24	335,847	6.96*	
Flare No. 25	498,000	None	
Flare No. 26	1,407,000	6	
Flare No. 27	70,000	0.06	Clean Flare

* These flares share a flare gas recovery system

B. EMISSION INVENTORY

According to the 2003 AQMP, the SO_2 emissions inventory for refinery flares, based on the 1997 annual reports for emissions fee billing (EFB), is 4.14 tons per day (the initial number, based on unaudited data at the time the AQMP was published, was 4.4 tons per day). For 2006 and 2010, this inventory is projected to be reduced by 50 percent through the implementation of Step II of control measure CMB-07, and the AQMP assumes concurrent emission reductions for the other criteria pollutants. The proposed amendment of Rule 1118 will implement Step II of the control measure and further reduce emissions to the extent feasible.

Flare emissions are reported on a quarterly basis per current requirements in Rule 1118, and are calculated based on flare vent gas flows and weekly samples that are analyzed to determine the concentration of total sulfur, expressed as sulfur dioxide, and the higher heating value (HHV) of the vent gas. It has to be noted that these emissions are different from the annual emissions reported under EFB program, where reported flare emissions are calculated based on crude throughput and the amount of elemental sulfur produced at each facility, using appropriate emission factors.

A summary of the quarterly reports, showing Rule 1118 annual flare emissions, from 200~~1~~0 through 2003, extracted from the September 2004 report presented to the Governing Board and the reported flare emissions for 2004 is shown in Table IV – 2.

Table IV – 2
Rule 1118 Reported Annual Flare Emissions (Tons)

Year	Flow (mmscf)	NOx	VOC	CO	PM10	SOx	Total
2000	4,085	136	125	733	43	2,633	3,670
2001	8,324	380	456	2,058	87	1,793	4,774
2002	2,440	83	78	450	25	754	1,390
2003	2,235	79	75	423	23	735	1,335
2004	2,392	93	70	364	27	352	906

The data in the table shows that flare emissions have decreased in the years following the adoption of the rule in 1998, as the refineries became more sensitive to flaring issues and implemented voluntary measures to reduce the vent gas flow combusted in the flares and better managed flare operations. It is important to note that these voluntary reductions in flare gas flow and associated emission reductions were generally not achieved through the installation or modification of gas recovery capacity or flare gas treatment systems. Since 1998, only one local refinery has installed control equipment in 2001; a flare gas recovery system for one of its flares that resulted in significantly reduced emissions from that flare.

Another reason for the drop in emissions was found to be the correct measurement of flare flows. A refinery discovered it had erroneous flare flow readings that led to reporting inflated emissions. An investigation of the problem concluded that the flow meter located before the water seal was counting both the flow towards the flare and the reverse flow to a recovery compressor, although no actual vent gas was going past the water seal and combusted in the flare. The refinery relocated the flow meter in the flare stack and eliminated the problem. Therefore, in order to get reliable emission data, it is necessary that the flow meters be located in a representative location after the water seals to ensure that a true flow to the flare is registered, or they must be equipped with totalizing capability to subtract any reverse flows to flare gas recovery systems.

The rest of the reductions resulted primarily from voluntary changes in operations, such as extending the time for shutting down or starting up units to minimize flaring, training operators to avoid routine flaring, as well as a commitment from management to minimize flaring. However, none of these measures are required by the current rule and as such, are not considered enforceable and permanent.

An analysis of the flare flow, events, and emissions data submitted to the AQMD since 1999 clearly shows a downward trend, it also shows variability from year to year. This variability is due in large part to emergencies, the specific unit(s) that undergo turnaround(s) in that year, other startups and shutdowns, and essential operational needs. Since these events can vary year to year, so will the number and type of flare events and the flare emissions. Therefore, it is appropriate to average the annual flare emissions to develop a representative baseline emissions inventory for emissions reductions and cost analysis calculations. Based on an analysis of the data submitted and discussions with refinery representatives, staff concluded that the 2000 data may not be very reliable due to compliance issues and because of problems related to the implementation of this recently adopted flare monitoring rule. Also, one refinery installed additional vent gas recovery in 2001; this installation would result in permanent emissions reductions from 2002 and beyond. Therefore, staff has determined that the most representative data for these variable flare operations and future releases are from years 2002, 2003 and 2004.

Table IV - 3
Flare Emissions Average 2002-2004

Year	NO_X	NMHC	CO	PM10	SO_2	Total
Average Emissions (TPY)	85	74	412	25	613	1,209
Average Emissions (TPD)	0.23	0.20	1.13	0.07	1.68	3.31

Based on emissions data from Table IV – 2, Table IV – 3 shows the flare emissions average for the period 200~~1~~2 through 2004. The Rule 1118 average reported SO_2 emissions is 613 tons or 1.68 tons per day, while the average emissions total for all the criteria pollutants is 1,209 tons, or 3.31 tons per day. This inventory will be used as the baseline for calculating the emission reductions associated with the proposed amended rule and its cost effectiveness.

C H A P T E R V

EMISSION REDUCTIONS

As shown in the previous chapter, flare emissions have trended lower since the rule was first adopted in 1998. As monitoring of flare flows was initiated to comply with the rule, refinery operators became aware of the high amounts of vent gas routed to flares and implemented procedures to minimize emissions. Although the reductions are substantial, staff believes that further emission reductions are feasible for the industry. In September 2004, after staff presented the "Evaluation Report on Emissions from Flaring Operations at Refineries", the AQMD Governing Board directed staff to initiate the amendment of Rule 1118. The performance targets in this rule amendment will result the installation of additional controls for flaring operations, as recommended in the Evaluation Report, to prevent backsliding in the emissions that have been reduced over the last several years.

The proposed amended rule requires refineries to gradually lower their annual sulfur dioxide emissions from a baseline average of approximately 1.68 tons per million barrels of crude processed to 1.5 tons per million barrels of crude processed in calendar year 2006, 1.0 ton per million barrels of crude processed in calendar year 2008, 0.7 ton per million barrels of crude processed in calendar year 2010 and 0.5 ton per million barrels of crude processed in calendar year 2012. The total processing capacity of the refineries in the basin, based on industry data, is approximately 1 mmbbl/day, therefore projected annual sulfur dioxide emission~~s~~ reductions for 2012 are 430.7 tons.

These reductions can be achieved by establishing a requirement that limits the use of flares only for emergencies, shutdowns and startups and certain essential operational needs and elimination of routine flaring. To ensure that total industry emissions will stay below the limit and prevent backsliding, the proposed amended rule has a mitigation fee provision in place. However, staff believes that by year 2012, flare sulfur dioxide emissions will be well below 0.5 ton per day and does not expect that any facility will have to pay mitigation fees, based on the current downtrend in emissions and the effect of the controls in the proposed rule amendment.

As the refineries minimize the amount of vent gas sent to flares, there will be concurrent emission reductions of other criteria pollutants. This is due to the fact that concurrent emissions are calculated as a function of the flare vent gas volume and the heating value of the flare gas. It is assumed that, since the average heating value of the vent gas is expected to stay constant, the lower vent gas volume will translate into proportionally lower emissions of NOx, CO, ROG and PM10.

Refineries E and H have reported significantly higher flare flows when compared to other refineries since the rule was adopted. During the interviews staff had conducted with all refineries subject to PAR 1118, Refinery H has informed staff that it has completed a flare gas optimization project in 2004 and that an additional flare gas recovery system will also be installed by 2008; moreover, Refinery E has also committed to the AQMD to increase its vapor recovery and gas treating capacity and to install flare gas recovery systems to significantly reduce flare emissions.

Staff has calculated the average total flare flow and a breakdown of the reasons for venting for 200~~1~~2 through 2003, which can be found in Table V – 1. This information was based on data from the September 2004 "Evaluation Report on Flares at Petroleum Refineries." For the same reason as explained before, the data for year 2000 and 2001 ~~was~~were not included in the calculation of the average flow since ~~it~~ the 2000 flow data was determined to be unreliable and a flare gas recovery system was installed at one refinery in 2001, which significantly reduced emissions from one of its' flares.

Table V – 1
Average Flare Flows and Reasons for Flaring 2002-2003

<table>
<tr><th colspan="3">Reasons for Flaring</th><th>Flow (mscf/year)</th><th>% of Total</th></tr>
<tr><td colspan="3">Emergency Recordable</td><td>276,544.5</td><td>11.755</td></tr>
<tr><td rowspan="7">Non- Emergency</td><td colspan="2">Non-Recordable</td><td>1,126,875</td><td>48.15</td></tr>
<tr><td rowspan="6">Recordable Events</td><td>Unknown</td><td>113474.5</td><td>4.775</td></tr>
<tr><td>Maintenance</td><td>130,738</td><td>5.615</td></tr>
<tr><td>Planned Startup/Shutdown</td><td>289,115</td><td>12.425</td></tr>
<tr><td>Process Vent</td><td>50,985.5</td><td>2.155</td></tr>
<tr><td>Turnaround Activities</td><td>240,031</td><td>10.37</td></tr>
<tr><td>Fuel Gas Imbalance</td><td>109,730.5</td><td>4.76</td></tr>
<tr><td colspan="3">Total Average Flow</td><td>2,337,493</td><td>100.00</td></tr>
</table>

As stated in Table V – 1, emergencies, maintenance, start-ups and shutdowns, turnaround activities, process vent and fuel gas imbalances represent approximately ~~53~~47 percent of the total flow. The remaining ~~4~~53 percent represents the volume of non-recordable and unknown non-emergency events that has a potential to be recovered/minimized.

Based on an analysis of the reported flare data and discussions with two "larger" of the three facilities that have been identified in the staff report as needing additional gas recovery and treatment system capacity to comply with PAR 1118, staff has determined that Refineries E, F and H will install flare vent gas recovery and treatment systems with a maximum capacity of 13.3 million standard cubic feet per day (mmscfd). The average capacity of 9 mmscfd is equivalent to 3,285,000 mscf per year (see Chapter VI – Cost and Cost Effectiveness for additional discussion and analysis of these vent gas recovery and treatment systems). This average recovery and treatment capacity represents more than 100 percent of the average annual flare flow, as found in Table V-1. Staff anticipates other refineries will initiate additional measure to minimize vent gases being sent to the flares. Therefore, with the increase in vent gas recovery and treatment capacity and additional voluntary flare minimization measures to be implemented, staff has determined that the baseline (three year average) emissions of criteria air contaminants other that sulfur dioxide will be reduced by 75 percent or more. Sulfur dioxide emissions will be reduced from the baseline of 1.68 tons per year to 0.5 ton per year by year 2012.

From the baseline emissions inventory representing the 200~~1~~2-2004 annual emissions averages and using the emissions reduction analysis above, the projected 201~~0~~2 flare emissions are as shown in Table V – 2. Although actual sulfur dioxide emission reductions are anticipated to be significantly higher than what it is assumed in this table, for the purpose of this analysis, emission reduction estimates were based on the 201~~0~~2 annual sulfur dioxide performance target of 0.~~7~~5 ton per million barrels of crude processed for PAR 1118.

Table V-2

Summary of AQMD Emission Reductions (Tons per Year)

Pollutant	Year		Emissions Reductions
	Baseline	2012	
SO_2	613	183	430
NOx	85	38	47
PM10	25	10	15
VOC	74	41	33
CO	412	198	214
Total	**1,209**	**470**	**739**

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C H A P T E R VI

COST AND COST-EFFECTIVENESS

A. COSTS

The proposed amendment seeks to implement the most feasible and cost-effective control options in order to reduce flare emissions. This chapter presents an overview of the costs refineries will have to incur in order to comply with the new requirements and the cost-effectiveness of implementing these requirements.

Since the proposed rule will only allow venting of vent gases during an emergency, shutdown, startup, turnaround or essential operational need and to minimize flaring, it is assumed that some refineries will need to install new flare gas recovery and gas treating systems, whereas other refineries may have to increase their existing flare gas recovery and treating capacity in order to comply with this proposed rule requirement. These are technologically feasible pre-combustion controls that were suggested in the conclusion of the “Evaluation Report on Emissions from Flaring Operations at Refineries" presented to the AQMD Board on September 3, 2004.

As shown in Table IV-1, of the seven oil refineries subject to the rule, three do not have any flare gas recovery for their flares. Staff expects these three refineries to install flare gas recovery systems and additional gas treating capacity. Based on the last four years, the other four refineries have adequate flare gas recovery capacity and are not expected to incur significant control equipment costs to comply with the proposed amended rule.

In order to meet the monitoring requirements, the refineries where the flow meters are located before the water seals at flares equipped with flare gas recovery compressors will need to upgrade the flow meters with totalizing and low flow measurement capability to accurately indicate the actual vent gas flow to the flare. Also, flow meters will need to be installed on all flares for the measurement of the purge and pilot gas flow. All refineries will have to equip their emergency and general purpose flares with heat content analyzers and total sulfur analyzers.

Until the analyzers are certified by the Executive Officer, refinery operators will be required to conduct sampling for both higher heating value and total sulfur daily. If the total sulfur analyzer pilot program to be conducted in 2006 demonstrates that the current sulfur monitoring technology is not feasible, an additional cost for automated sampling systems and the processing of samples for total sulfur content must be included in the costs to implement PAR 1118.

Staff will calculate the costs associated with the proposed amendment; two scenarios will be considered. Costs common to both scenarios include additional vent gas recovery and treatment systems (capacity), upgrade flare gas flow meters, install purge/pilot gas flow meters, and annual costs associated with the newly installed equipment (parts and maintenance), surveys of pressure relief devices, conducting flow meter tests and Specific Cause Analyses. In Scenario 1, it will be assumed that all of refineries will install heat content and total sulfur analyzers. In Scenario 2, it will be assumed that only heat content analyzers are installed along with automated sampling systems and that the concentration of total sulfur, expressed as sulfur dioxide, of the vent gas will be determined by laboratory analysis.

Scenario 1

Capital Costs

Under the first scenario, it will be assumed that:

- The three refineries that currently do not have flare gas recovery systems (for eight flares) will install a total of four flare gas recovery and gas treating systems. Staff assumes that at the first refinery, two systems will be installed; one system will control three flares and the other two flares. Another system serving a pair of flares will be installed at the second refinery. The third refinery will install one control system for its one flare.

- Refineries will install 23 heat content analyzers for the emergency/general service flares;
- Refineries will install 23 total sulfur analyzers for the emergency/general service flares;
- Refineries will install 50 purge/pilot gas flow meters (one for each emergency/general service flare); and
- Refineries will upgrade the emergency/general service flare flow meters with totalizing and low flow capability.

A synopsis of the projected rule required changes for emergency and general service flares is shown in Table VI-1.

Table VI – 1
Scenario 1 Rule Required Modifications

Flare ID	Flare Gas Recovery	Gas Treatment	Higher Heating Value Analyzer	Total Sulfur Analyzer	Flow Meter Upgrade	Purge/Pilot Flow Meter
1			1	1	1	2
2			1	1	1	2
3			1	1	1	2
4	0.5*	0.5*	1	1	1	2
6			1	1	1	2
7	0.5*	0.5*	1	1	1	2
8			1	1	1	4***
9	0.5*	0.5*	1	1	1	2
10			1	1	1	2
11	1	1	1	1	1	2
13			1	1	1	2
15			1	1	1	4***
16	0.5*	0.5*	1	1	1	2
17			1	1	1	2
18			1	1	1	2
19	0.33**	0.33**	1	1	1	2
20	0.33**	0.33**	1	1	1	2
21			1	1	1	2
22			1	1	1	2
23			1	1	1	2
24			1	1	1	2
25	0.33**	0.33**	1	1	1	2
26			1	1	1	2
Total	**4**	**4**	**23**	**23**	**23**	**50**

* Common flare gas recover and treatment system serving two flares
** Common flare gas recover and treatment system serving three flares
*** System consisting of two flares in cascade (common flow meter)

The cost for a flare recovery and gas treating system will be estimated based on data submitted to the AQMD by two local refineries as part of an application for permits to construct and operate, and data obtained from the Montana Department of Environmental Quality (DEQ) for a petroleum refinery located in Billings, Montana.

One local refinery installed a 10 million standard cubic feet per day (mmscfd) flare gas recovery system in 1993 for $10 million and a 48 mmscfd gas treating system for $23.2 million. The other local refinery installed in 2001 a flare gas recovery system with a capacity of 6 mmscfd for $9.2 million. The Billings, Montana refinery installed a flare gas recovery and gas treating system with a design capacity of 4 mmscfd for $7.7 million in 2003. Staff will determine the average normalized cost of the three examples studied to calculate the cost of flare gas recovery and gas treating systems needed to comply with the requirements and annual emission targets of PAR 1118.

Based on the first case study, installed in 1993, the cost for a flare recovery system and gas treating unit, normalized per one mmscfd, was $1.48 million ($1 million and $0.483 million respectively). In 2005 dollars, based on the Nelson Farrar Index published in the Oil and Gas Journal, the cost would be $1.43 million and $0.734 million respectively, for a total of $2.16 million per mmscfd.

Based on the second case study, installed in 2003, the normalized cost of the flare gas recovery system and corresponding gas treating system per one mmscfd was $1.93 million, of which $1.52 million was for flare gas recovery and $0.41 million was for the gas treating system. In 2005 dollars, based on the Nelson-Farrar Index, the cost would be $1.6 million and $0.48 million, respectively, or $2.08 million per mmscfd.

Based on the third case study, installed in 2001, the normalized cost for a flare gas recovery compressor per one mmscfd was $1.53 million. In 2005, this cost, based on the Nelson Farrar Index, would be $1.645 million. No gas treating system was installed in conjunction with this flare gas recovery system. However, based on the two other case studies, the cost of a flare gas recovery system is approximately 72 percent of the cost of a system consisting of both flare gas recovery and gas treating which is calculated as $0.635 million. Therefore, the total cost of a complete system would be $2.28 million per mmscfd.

Based on the above case studies, the average cost to install a flare gas recovery and treating system, based on three different system capacities of 4 mmscfd, 6, mmscfd and 10 mmscfd, is $2.17 million per mmscfd (2005 dollars).

Staff reviewed the Rule 1118 quarterly reports for the year 2003 and selected the quarters with the highest flows for the eight flares without flare gas recovery systems, then calculated the daily average flows for those quarters. API 521 guidelines recommends that the capacity of a flare gas recovery system be able to handle a wide variation in flow rates, and an Oil and Gas Journal article published on December 7, 1992, recommends the recovery capacity to be 2-3 times the average flow rate.

Based on this information, staff has estimated that for the first refinery, one system with a maximum capacity of 6 mmscfd, serving three flares, and a second system serving two flares with a maximum capacity of 4 mmscfd would be adequate. For the second refinery, staff projected that a system with a capacity of 3 mmscfd serving two flares would be adequate. For the third refinery staff estimated that a system with a capacity of 0.3 mmscfd for its flare would be adequate.

The costs to install the flare gas recovery and treating systems are estimated by using the average $2.17 million per mmscfd factor times the projected capacities needed by the refineries with no control on their emergency/general service flares to comply with PAR 1118. The costs are summarized in Table VI – 2:

Table VI – 2
Total Installed Cost for Flare Gas Recovery and Gas Treatment

Flare ID	Maximum Capacity(mmscfd)	Total Installed Cost ($)
19, 20 and 25	6	13,020,000
9 and 16	4	8,680,000
4 and 7	3	6,510,000
11	0.3	651,000
Total	**13.3**	**$28,861,000**

The breakdown by flares of the projected installations, with the highest average daily flows and maximum capacities is shown in Table VI-3

Table VI – 3
2003 Highest Quarterly Flows and Daily Average Flows

<table>
<tr><th colspan="2" rowspan="2">Flare ID</th><th rowspan="2">Highest 2003 Quarterly Flow (mmscf)</th><th rowspan="2">Daily Average Flow (mmscfd)</th><th colspan="2">Projected Treatment Capacity (mmscf)</th></tr>
<tr><th>Min.</th><th>Max.</th></tr>
<tr><td>25</td><td rowspan="3">Common System</td><td>87.03</td><td>0.97</td><td rowspan="3">2.25</td><td rowspan="3">6</td></tr>
<tr><td>20</td><td>59.6</td><td>0.66</td></tr>
<tr><td>19</td><td>55.98</td><td>0.62</td></tr>
<tr><td>16</td><td rowspan="2">Common System</td><td>32.27</td><td>0.36</td><td rowspan="2">1.49</td><td rowspan="2">4</td></tr>
<tr><td>9</td><td>101.61</td><td>1.13</td></tr>
<tr><td>4</td><td rowspan="2">Common System</td><td>49.43</td><td>0.55</td><td rowspan="2">1.09</td><td rowspan="2">3</td></tr>
<tr><td>7</td><td>48.53</td><td>0.54</td></tr>
<tr><td colspan="2">11</td><td>9.01</td><td>0.1</td><td>0.1</td><td>0.3</td></tr>
<tr><td colspan="3">Total</td><td>4.93</td><td>4.93</td><td>13.3</td></tr>
</table>

The cost of installing flow meters for purge gas and pilot gas is estimated by assuming that these devices would be connected to computerized control systems and therefore, will need data transmitters. An orifice plate flow meter and transmitter combination was quoted at $2,280 by a parts supplier, and labor is estimated at 10 hours at a rate of $35 per hour each. The total installed cost, assuming an additional 10 percent for software, instrumentation, and taxes is therefore estimated at $2,858 per flow meter and for 50 flow meters the total cost will be $142,900.

The proposed rule requires the flare gas flow meters to be upgraded with totalizing and low flow capability. This upgrade was quoted at $10,000 per flow meter by GE Panametrics, therefore the total cost for 23 flow meters will be $230,000.

The cost of the heat content analyzers was quoted at $70,775 each by Cosa Instruments. Assuming that the total installed cost, including a sample conditioning unit, shelter, piping, electrical, taxes, permitting and certification will be $150,000, the total installed cost for 23 analyzers is estimated at $3,450,000.

The cost of a total sulfur analyzer, including taxes, shipping, startup/commissioning was quoted by ThermoElectron at $79,308. The additional cost of installation for the total sulfur analyzer to the heat content analyzer and sample conditioning system is estimated at $5,000. Therefore the total installed cost is estimated at $84,308 each and $1,939,084 for 23 analyzers.

In order to calculate the cost effectiveness of the rule, the capital costs of the proposed amendment will need to be determined. It will be assumed that the flare gas recovery systems, gas treating systems and flow meters have an equipment life of 25 years, whereas the heat content analyzers and total sulfur analyzers have a 10 year equipment life. In order to have a common basis for equipment life to calculate the cost effectiveness, the cost of the analyzers will be referenced to a 25 year equipment life. For this purpose, it is assumed that during a 25 year period three sets of analyzers will have to be purchased. The cost of this expenditure is calculated below:

$$C_{analyzers} = C1 + C2 + C3$$

1st Set Cost is at current cost:

C1 = $3,450,000 + $1,939,084 = $5,389,084

The 2nd set is to be purchased after 10 years. Its cost in today’s dollars is calculated assuming a 4% real interest rate at ten years using the corresponding present worth factor of 0.6756 will be:

C2 = $5,389,084 * 0.66756 = $3,640,865

The 3rd set of analyzers is to be purchased after 20 years. The cost in today’s dollars, at 4% real interest rate at twenty years using the corresponding a present value factor of 0.4564 will be:

C3 = $5,389,084 * 0.4564 = $2,459,578

The total cost of the analyzers will therefore be, over a 25 year period:

$C_{analyzers}$ = C1 + C2 + C3 = $11,489,527

The flare gas recovery and gas treatment systems will require a permit to construct and operate from the AQMD. The permit application evaluation fee for one system is $7,233. As previously stated, the staff has determined that four control systems will need to be installed and operated to meet the annual sulfur dioxide performance targets in PAR 1118. Therefore, the permit application fees/cost to the refineries is $28,932.

A one-time CEMS certification fee is also required. The certification fee includes the initial application approval, approval of the test protocol and approval of the performance test results. The maximum fee is $7,693 for a monitoring system consisting of up to four components. The system required to comply with PAR 1118 consists of three (flow, higher heating value and total sulfur). The industry will install 23 higher heating value and total sulfur analyzer systems to comply with the monitoring requirements in PAR 1118. Therefore, the cost to certify the analyzer systems will be $176,939.

Under Scenario 1, the total estimated capital costs associated with the rule, based on the assumptions stated above, are summarized in Table VI-4.

Table VI – 4
Total Capital Costs Scenario 1

Equipment	Cost ($)
Flare Gas Recovery/Treatment Systems	28,861,000
Higher Heating Value/Total Sulfur Analyzers (Initial + 2 replacements)	11,489,527
Pilot/Purge Gas Meters	142,900
Flow Meter Upgrades	230,000
Permit Processing Fees	28,932
Analyzer (CEMS) Certification Fees	176,939
Total Capital Cost	**$40,929,298**

<u>Annual Costs</u>

The refineries will also incur annual costs associated with the newly installed equipment (parts and maintenance), surveys of pressure relief devices, conducting flow meter tests and Specific Cause Analyses.

Assuming that annual cost, such as for parts, maintenance, repairs, calibration gases, taxes, insurance and power represent 10 percent of the capital cost (including only the initial purchase of analyzers), the annual cost is estimated as $3,482,886.

Another annual cost will be for conducting surveys of the pressure relief devices connected to flares. These surveys can be conducted concurrently with the Rule 1173 quarterly inspections and it is estimated that on average an additional 200 hours per refinery and 100 hours for the hydrogen plant will be spent per year for this task. At $25 per hour, for seven refineries and a hydrogen plant, the annual cost will be $37,500.

Another annual cost will be for verifying the accuracy of flow meters. Flow verification costs were quoted at $1,500 per day for up to two flares. The annual cost for flow verification is estimated as $25,000 as shown below:

Table VI – 5
Annual Cost for Flow Meter Verification

Facility	No. of Flares	Estimated Annual Cost ($)
A	4	3,000
B	1	1,500
C	3	3,000
D	3	3,000
E	5	4,500
F	1	1,500
G	6	4,500
H	5	4,500
Total	**27**	**$25,500**

The proposed rule will require refineries to conduct Specific Cause Analyses (SCA) for flaring events exceeding 500 pounds of sulfur dioxide, 100 pounds of VOC or 500,000 scf of vent gas. The investigation of flaring events exceeding 500 pounds of sulfur dioxide would not represent an additional cost since this is a requirement under federal law.

A review of the 2003 flaring events meeting these criteria stated in the previous paragraph found 980 flare events that had less than 500 pounds of sulfur dioxide emissions. However, these flaring events, representing 80 percent of the vent gas flow, included shutdowns and startups, turnaround activities or fuel gas balancing. The facilities subject to PAR 1118 are not required to submit an SCA for these categories of vent gas release under the proposed rule. Therefore, assuming that a corresponding 80 percent of these 980 events would not be required to submit an SCA, approximately 200 additional events would need to be investigated. The local refineries have estimated that the time needed to complete an SCA ranges from 40 to 200 hours. Based on this information, staff has estimated that a refinery would spend an average of 80 hours conducting SCA investigations, at an average rate of $50 per hour. The total annual cost of conducting an additional 200 SCA investigations that may be required as part of the proposed amended rule is therefore estimated at $800,000. The total annual costs associated under Scenario 1, as calculated above, are summarized in Table VI - 6:

Table VI -6
Total Annual Costs Scenario 1

Item	Annual Cost ($)
Maintenance/Parts for Controls Equipment, Flow Meters, and Higher Heating Value and Total Sulfur Analyzers	3,482,886
Leak Surveys	37,500
Flow Meter Verification	25,500
Specific Cause Analyses	800,000
Control Equipment Annual Operating Fee	2,951
Total	**$4,348,836**

Scenario 2

For scenario 2, the estimated capital costs will be identical to Scenario 1, except that it will not include the installation and operation of total sulfur analyzers but will include the addition of 23 automated sampling devices. A summary of the proposed rule requirements is shown in Table VI -7:

Table VI – 7
Scenario 2 Rule Required Modifications

Flare ID	Flare Gas Recovery	Gas Treating	HHV Analyzer	Automated Sampler	Flow Meter Upgrade	Purge/Pilot Flow Meter
1			1	1	1	2
2			1	1	1	2
3			1	1	1	2
4	0.5*	0.5*	1	1	1	2
6			1	1	1	2
7	0.5*	0.5*	1	1	1	2
8			1	1	1	4**
9	0.5*	0.5*	1	1	1	2
10			1	1	1	2
11	1	1	1	1	1	2
13			1	1	1	2
15			1	1	1	4**
16	0.5*	0.5*	1	1	1	2
17			1	1	1	2
18			1	1	1	2
19			1	1	1	2
20	0.5*	0.5*	1	1	1	2
21			1	1	1	2
22			1	1	1	2
23			1	1	1	2
24			1	1	1	2
25	0.5*	0.5*	1	1	1	2
26			1	1	1	2
Total	**4**	**4**	**23**	**23**	**23**	**50**

* Common system serving two flares

** System consisting of two flares in cascade (common flow meter)

The total installed cost of the automated sampling system is estimated at $5,000, and for 23 flares the cost will be $115,000.

As in Scenario 1, the cost of the 23 heat content analyzers will have to be referenced to a 25 year equipment life cycle; therefore it is assumed that 3 sets of analyzers have to be purchased during this period of time.

The cost for the initial set will be:

C1 = $150,000 * 23 = $3,450,000

After 10 years, in today's dollars, the cost of the second set in today's dollars will be:

C2 = \$3,450,000 * 0.6756 = \$2,330,820

After 20 years the cost of the third set of analyzers in today's dollars will be:

C3 = \$3,450,000 * 0.4564 = \$1,574,580

The total cost of the analyzers, assuming a 25 years life, will be:

$C_{analyzers}$ = C1 + C2 + C3 = \$7,355,400

The capital costs under Scenario 2 are summarized in Table VI-8:

Table VI – 8

Total Capital Costs Scenario 2

Equipment	**Cost (\$)**
FGRS/Amine Scrubbers	28,861,000
Heat Content Analyzers	7,355,400
Pilot/Purge Gas Meter	142,900
Flow Meter Upgrade	230,000
Automated Sampling System	115,000
Permit Processing Fees	28,932
Analyzer (CEMS) Certification Fees	176,939
Total Capital Cost	**\$36,910,171**

Under Scenario 2, all refineries will be required to take six additional daily samples for total sulfur per flare during the week, incurring additional annual costs. Assuming that the cost of processing a sample will average \$350, the annual cost of sampling will be:

Annual Sampling Cost = 23 flares * 6 samples /wk * 52 wks * \$350/sample

= \$2,511,600

The cost of maintenance, parts, power, insurance and taxes for equipment is assumed to be 10 percent of the total capital cost (including only the initial purchase of analyzers). Therefore, the total annual cost for the equipment and analyzers will be \$3,300,477.

A summary of the annual costs under Scenario 2 is presented in Table VI – 9.

Table VI – 9
Total Annual Costs Scenario 2

Item	Annual Cost ($)
Maintenance/Parts for Equipment	3,300,477
Leak Surveys	37,500
Flow Meter Verification	25,500
Specific Cause Analysis	800,000
Daily Sampling	2,511,600
Control Equipment Annual Operating Fee	2,951
Total	**$6,678,028**

Recovered Vent Gas - Cost Savings

The flare gas recovery systems will recover vent gases that otherwise would be combusted in the flares. The recovered gas, after treatment, can be used as fuel gas or process feed, thus reducing operating costs for the refineries. Additional savings are realized by using less steam for the flare operations and extended flare tip life, minimizing repair costs; for this calculation, only the payback value of the recovered gas to be used as fuel gas or process feed is considered. This would represent annual savings that can lower the annual costs.

The following assumptions will be made:

- The annual average recovered gas volume is ~~3,285~~2,337 mmscf (see Chapter V – Emission Reductions)
- On average, only 60 percent of the recovered gas volume is valuable product (based on review of recovered gas samples from a local refinery)
- The value of recovered gas is estimated at $2 per mmBtu (www.johnzink.com – Flare Gas Recovery payback analysis)
- The average heat content of the recovered gas is 1,000 Btu/scf

Annual Savings = ~~3,258~~2,337 * 10^6 scf * 0.6 * 1,000 Btu/scf * $2/$10^6$ Btu = $~~3,909,600~~2,804,400

As emissions will decrease, the refineries will pay reduced annual emission fees to the AQMD, reducing their annual costs. Table VI – 10 lists the estimated annual emission fees savings by pollutant and the total savings for the industry.

Table VI – 10
Estimated Annual Emission Fees Savings

Pollutant	Fees* ($/ton)	Projected Reduction (tons)	Estimated Savings ($)
ROG	944.16	33	31,157
NOx	543.73	47	25,555
CO	4.64	214	993
PM10	720.72	15	10,811
SO_2	653.98	356	232,817
Total			**$290,439**

*Rule 301 – Table III-Emission Fees (June 3, 2005)

The total annual costs will then be:

For Scenario 1:

Total Annual Cost = $4,285,398 – $~~3,909,600~~2,804,400 – $290,439 = $~~85,359~~1,190,559

For Scenario 2:

Total Annual Cost = $6,6~~14,59~~78,028 – $~~3,909,600~~2,804,400 – $290,439 = $~~2,414,551~~3,583,189

B. COST-EFFECTIVENESS

In order to calculate the cost effectiveness of the proposed amendment, the present value of the capital cost and operating cost during the useful life of the control equipment and/or program must be calculated, using the following formula:

$$PV = C + A * PVF$$

where:

PV = Present Value to implement the proposed new rule requirements

C = Capital costs to implement proposed new rule requirements

A = Annual costs to implement proposed new rule requirements

PVF = Present Value Factor, Equal Series

= 15.62 (25 years equipment life and 4% real interest rate).

Cost Effectiveness – SOx Emission Reductions Only

Scenario 1:

C = $40,929,298

A = $~~85,359~~1,190,559

PV1 = $40,929,298 + $~~85,359~~1,190,559 * 15.62 = $~~42,262,606~~59,525,830

The cost effectiveness is calculated with the discount cash flow (DCF) method:

CE1 = PV1 / (ER * EL)

where:

CE1 = Cost Effectiveness for Scenario 1

ER = Emission Reduction for SO_2, 431 tons per year

EL = Equipment life, 25 years

CE1 = $~~42,262,606~~59,525,830 / (431 tons * 25) = $~~3,922~~5,524 per ton of SO_2 reduced

Scenario 2

C = $36,910,171

A = $~~2,414,551~~3,583,189

PV2 = $36,910,171 + $~~2,414,551~~3,583,189 * 15.62 = $~~74,625,458~~92,879,583

CE2 = $~~74,625,458~~92,879,583 / (431 tons * 25) = $~~6,926~~8,620 per ton SO_2 reduced

Therefore, the cost effectiveness for this proposed amendment is estimated to be between $~~3,922~~5,524 and $~~6,926~~8,620 per ton of SOx reduced.

Cost Effectiveness – Total Emissions Reductions (Excluding CO)

If reductions in the other pollutants were to be considered, the cost effectiveness would be:

CE = PV / (TER * EL)

where:

PV = Present Value to implement the proposed new rule requirements

TER = Total emission reduction for the other criteria pollutants less CO, tons per year

EL = Equipment life, 25 years

From Table V – 2:

TER = 431 tons + 47 tons + 33 tons + 15 tons = 526 tons

Scenario 1

CE1 = $~~40,929,298~~59,525,830 / (526 * 25) = $~~3,112~~4,527 per ton of pollutant reduced

Scenario 2

CE2 = $~~74,625,45~~92,879,583~~8~~ / (526 * 25) = $~~5,675~~7,063 per ton of pollutant reduced

Therefore, if reductions for the other criteria pollutants, less CO, are included in calculations, the cost effectiveness of the proposed amendments ranges between $~~3,112~~4,527 and $~~5,675~~7,063 per ton of pollutant reduced, excluding CO.

C. INCREMENTAL COST-EFFECTIVENESS

Staff is required under state law to determine an incremental cost effectiveness of the most stringent control scenario. Staff believes that the most stringent control scenario would require petroleum refineries to control all vent gases excluding off specification gas and vent gases resulting from emergencies.

An analysis of the reported flare gas flow and emissions data for years 2002, 2003, and 2004 and vent gas recovery and treatment capacity associated with flares is summarized as follows:

Flare gas recovery and treatment system capacity

Current:	51 mmscfd
Future implementing PAR1118 requirements:	64.5 mmscfd
Additional capacity to treat maximum daily flow recorded:	119 mmscfd
(excluding off spec gas and emergencies)	

PAR 1118 - 2012 Emissions

SO_2 performance target:	0.50 TPD
Total emissions, less SO_2 and CO:	0.24 TPD
Reported non-emergency, SO_2:	94% (based on 2002 and 2003 data)

Reported non-emergency, other 68% (based on 2002 and 2003 data)

Capital cost of the additional flare gas recovery and treatment system capacity

Estimate cost of system based on a previously determined cost of \$2.17 million per million standard cubic feet per day treatment capacity (mmscfd)

\$2.17 million/mmscfd * 119 mmscfd = \$258,227,362

Annual cost is estimated to be 10 percent of the capital cost

\$258,227,362 *0.10 = \$25,822,362

SO_2 Emission Reductions Only

PV = \$258,227,362 + \$25,822,362 * 15.62 = \$661,578,503

CE = PV / (Incremental ER * EL)

CE = \$661,578,503 / [0.5 tons/day * 0.93 * 25 yrs * 365 days/yr]

= \$155,918 per ton of SO_2 reduced

Total Emissions Reductions, Less CO

PV = \$258,227,362 + \$25,822,362 * 15.62 = \$661,578,503

CE = \$661,578,503 / {[0.5 ton/day * 0.93 + 0.24 ton/day * 0.68] * 25 yrs * 365 days}

= \$115,412 per ton of air contaminant reduced

Therefore, the incremental cost effectiveness for this proposed amendment is estimated to be between \$115,412 and \$155,918 per ton of air contaminant reduced.

C H A P T E R VII

COMPARATIVE ANALYSIS

PAR 1118	U.S. EPA 40CFR 60.18 and Subpart J
– ***Applicability***	
– Flares at refineries, sulfur recovery plants and hydrogen production plants	– Flares built or modified after June 11, 1973, subject to 40CFR 60 Subpart J – Flares controlling vents from piping components subject to 40CFR 60 Subpart GGG, from storage tanks subject to 40CFR 60 Subpart K_b, or from wastewater systems subject to 40CFR 60 Subpart QQQ
– ***Requirements***	
– Flares to be operated with no visible emissions – Flares to be operated with a pilot flame present at all times – Annual acoustical or thermal surveys of PRD's directly connected to flares – Specific Cause Analysis of flare events exceeding: o 500 lbs SO_2 o 100 lbs VOC o 500,000 scf vent gas combusted – Cause of flare events where at least 5,000 scf of vent gas are combusted – Effective September 1, 2006, submit the following information: o Technical specifications on flare systems including an audit of gas recovery and treating system capacity and storage capacity for excess vent gases o A description of equipment installed and procedures implemented within the last 5 years to minimize flaring o A description of equipment to be installed or procedures to be implemented to minimize or eliminate flaring – Effective January 1, 2007, operate flares in such a manner as to minimize flaring and only combust vent gas during emergencies, shutdowns, startups, turnarounds or essential operational needs	– Flares to be operated with no visible emissions – Flares to be operated with a pilot flame present at all times – Air or steam assisted flares shall only combust gases with a heat content of 300 BTU/scf or more – The exit velocity of the vent gas is limited by the net heating value of the vent gas – Flares shall not be used to combust gases containing more than 0.1 gr/dscf (160 ppm) H_2S, averaged over 3 hours

PAR 1118	U.S. EPA 40CFR 60.18 and Subpart J
Effective January 1, 2009, combustion in flares of gases with hydrogen sulfide concentration exceeding 160 ppm, averaged over 3 hours, is prohibited, unless in an emergency, shutdown, startup or PRD leakage	
– ***Performance Targets***	
– Specific annual performance targets for subject facilities based on their crude ~~throughput~~processing capacity – Mitigation fees assessed for exceedance of performance targets	– N/A
– ***Flare Minimization Plans***	
– Triggered by exceedance of performance target, or – To include policies and procedures and process and equipment upgrades implemented to prevent future exceedances – Subject to public review and comment	– N/A
– ***Monitoring and Recording***	
– Until July 1, 2007, continuous monitoring of vent gas flow, sample daily and during sampling events for vent gas higher heat content and total sulfur as SO_2 or install continuous or semi-continuous analyzers – After July 1, 2007, continuous monitoring of vent gas flow, higher heat content and semi-continuously for total sulfur as SO_2 – The presence of pilot flames monitored with thermocouples or equivalent devices – Effective July 1, 2006, video monitors with date and time stamp must be used to determine visible emissions – Effective January 1, 2007: o automated sampling system required for vent gas sampling	– The presence of pilot flames monitored with thermocouples or equivalent devices

PAR 1118	U.S. EPA 40CFR 60.18 and Subpart J
o Pilot and purge gas flow must be monitored	
– ***Recordkeeping***	
– Video monitoring records to be kept for 90 days – Other records to be kept for five years	– Records to be kept at least two years – Records to be kept at least five years for Title V facilities
– ***Notification and Reporting***	
– 24 hour telephone service provided for public inquiries on flare events – 1 hour notification of events exceeding: o 500 lbs SO_2 o 100 lbs VOC o 500,000 scf vent gas combusted – 24 hour notification of planned events exceeding: o 500 lbs SO_2 o 100 lbs VOC o 500,000 scf vent gas combusted – Submittal of Specific Cause Analysis of qualifying flare events within 30 days or 60 days upon request – Quarterly reports in electronic format certified for accuracy by responsible facility official, to include: o Daily and quarterly flare emissions o Causes of flare events o Records of annual PRD o Monitoring system down times – Copies of notifications required by 40CFR 355 pertaining to reportable air releases	– Semiannual reports – Notifications required by 40CFR Subchapter 355 Emergency Planning and Community Right to Know Act (EPCRA) pertaining to reportable air releases
– ***Testing and Monitoring***	
– Visible Emissions determined with U.S. EPA Method 22, Appendix A, 40CFR 60	– Visible Emissions determined with U.S. EPA Method 22, Appendix A, 40CFR 60

PAR 1118	U.S. EPA 40CFR 60.18 and Subpart J
– Vent Gas higher heating value determined: o By ASTM Method D2382-88, ASTM Method D3588-91 or ASTM Method D4891-89 o Effective July 1, 2007 with continuous analyzer – Vent Gas total sulfur expressed as SO_2 determined: o By ASTM Method D5504-01 or District Method 307-91 o Effective July 1, 2007, with a semi-continuous analyzer – Flow monitored with a continuous flow measuring device requiring annual accuracy verification	– Net heating value of the vent gas determined with ASTM Method D2382-88 or D 4809-95 –
– ***Exemptions***	
– Sampling not required if: o There is a catastrophic event, or o Safety of sampling personnel is at issue – Emissions from flaring events due to force majeure or circumstances beyond the operators' control do not count towards annual performance targets	– Emergency or upset vent gas and relief valve leakage due to malfunctions may exceed a H_2S concentration exceeding 160 ppm

Facilities subject to PAR 1118 are also subject to the following AQMD rules:

Rule 401 – Visible Emissions

Rule 402 – Nuisance

Rule 431.1 – Sulfur Content of Gaseous Fuels

C H A P T E R VIII

DRAFT FINDINGS

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 - The AQMD Governing Board has determined that a need exists to amend Rule 1118 – Emissions from Refinery Flares, to make current emission reductions permanent and enforceable, and to achieve emission reductions to meet the federal and state ambient air quality standard for PM 10 and PM 2.5 and to clarify rule language.

Authority - The AQMD 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 AQMD Governing Board has determined that the proposed amendments to Rule 1118 - Emissions from Refinery Flares, are written and displayed so that the meaning can be easily understood by persons directly affected by them.

Consistency - The AQMD Governing Board has determined that Proposed Amended Rule 1118 - Emissions from Refinery Flares, is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, federal or state regulations.

Non-Duplication - The AQMD Governing Board has determined that the proposed amendments to Rule 1118 - Emissions from Refinery Flares, 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 AQMD.

Reference - In adopting these amendments, the AQMD Governing Board references the following statutes which the AQMD 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.

C H A P T E R IX

COMMENTS AND RESPONSES

ARB

Comment 1: Although the phrase "Flare Management (*Minimization*) Plan" is a central concept of the PAR 1118, the phrase is not included in the list of definitions. Staff recommends its inclusion.

Response 1: *PAR 1118 has been revised using the phrase "Flare Minimization Plan" (FMP). The latest proposal put greater emphasis on the minimizing flare events and emissions through the annual performance targets, which are significantly lower than previously presented at the June 29, 2005 Public Workshop. The latest proposal only requires an FMP from those refineries that exceed the annual performance targets. The required elements to be submitted as part of the FMP are listed under paragraph (e)(1), which effectively defines what an FMP is.*

Comment 2: Staff recommends that the definition of "Essential Operational Needs" be clarified so as to be limited to only those events clearly identified in an approved "Flare Management (*Minimization*) Plan".

Response 2: *PAR 1118 has been revised to include a definition of Essential Operational Needs.*

Comment 3: PAR 1118 ought to explicitly require that any pressure relief devices found to be defective or leaking be expeditiously repaired.

Response 3: *Pressure relief devices (PRDs), in particular PRDs that are connected directly to the flare gas header, can not be repaired without shutting down the process unit which they serve. Therefore, refineries typically repair defective or leaking PRDs during the process unit turnaround. To facilitate expeditious repair, PAR 1118 requires the refineries to conduct the PRD survey within 90 days prior to a turnaround.*

Comment 4: The district should include a mechanism to allow for public comment on the proposed Flare Management (*Minimization*) Plan [FMP] prior to each FMPs approval. The lack of specific quantifiable standards for an FMP to attain approval, as well as the fact that each FMP will be unique, make it imperative that a forum for public comment is included to provide all interested parties with the opportunity to provide critical input.

Response 4: *PAR 1118 has been revised to incorporate a provision that requires a 60 day public comment period for each Flare Minimization Plan (FMP) that has been reviewed and recommended for approval by the AQMD.*

Comment 5: Flare Management (*Minimization*) Plans should be required to be updated on an annual basis to incorporate improvements in flare management. Additionally, the district ought to include in the rule amendment a future commitment to evaluating Rule 1118 and making future recommendations to improve its effectiveness.

Response 5: *PAR 1118 has been revised to require submittal of a FMP or revised FMP whenever a refinery exceeds the annual SO_2 performance target. Staff will continue to analyze data that will be submitted to the AQMD as required by PAR 1118. As with other rules, staff will also assess the effectiveness of PAR 1118 to determine if future technologically feasible and cost effective amendments are necessary to achieve and maintain ambient air quality standards.*

Comment 6: In the preliminary draft staff report, the emission reduction calculation for sulfur compounds was made using a different methodology than was used to calculate the reduction of other criteria pollutants. This discrepancy in methods should be corrected.

Response 6 *The emission reduction for total sulfur, expressed as sulfur dioxide is based on the performance target in the rule, whereas the concurrent emission reductions for other combustion pollutants was based on the assumption that the flare vent gas flow will be reduced with the installation of additional flare gas recovery and treatment system(s).*

Minimization

Comment 7: The language in section (c) Requirements (2)(A) is extremely ambiguous. The lack of specificity in the language, "take steps to minimize emissions during such events", could provide a loophole for facilities operating flares, and could lead to disputes over enforcement.

Response 7: *PAR 1118 has been revised to include the requirement to minimize all flaring.*

Public Input and Involvement

Comment 8: The district should hold a public hearing and provide the opportunity for public comment prior to approving any FMP.

Response 8: *PAR 1118 has been revised to incorporate a provision that requires a 60 day public comment period for each flare minimization plan (FMP) that has been reviewed and recommended for approval by the AQMD.*

Comment 9: The public should be provided with quarterly flare reports online. The public has a right to emissions information and providing it online will allow the public to bypass the often long delays inherent in the public records request process.

Response 9: *Staff will post a summary of the quarterly flare emission reports on the AQMD web site.*

Mitigation Fees

Comment 10: Individual facility mitigation fees are preferable to mitigation fees based on industry-wide thresholds. Requiring mitigation fees to be paid based upon an industry-wide threshold is not an equitable arrangement for individual facilities, nor is it in keeping with environmental justice principles.

Response 10: *PAR 1118 has been revised to establish facility-specific performance targets and mitigation fees will only be assessed for emissions exceeding the annual SO_2 performance target.*

Comment 11: The PAR 1118 indicates that a mitigation fee of $25,000 per ton will be charged for all emissions. The applicability of that mitigation fee should be changed so that it pertains only to those emissions above the prescribed target.

Response 11: *PAR 1118 has been revised such that mitigation fees will only be assessed for emissions exceeding the annual SO_2 performance target.*

Comment 12: The cost of $25,000 per ton is excessive given previous fees of $10,000 per ton or the RECLAIM backstop ceiling of $15,000 per ton. Furthermore, these mitigation fees are being charged on top of an existing fee (AER). The rule should offer the ability for a facility to propose a local community project for which their mitigation fee payments could be used.

Response 12: *PAR 1118 has been revised such that any refinery exceeding the specified performance target in any calendar year, it will have to pay a mitigation fee of $25,000, $50,000 or $100,000 per each ton of sulfur dioxide over the limit, depending on whether excess emissions are no more than ten percent, greater than ten percent but no more than twenty percent or greater than twenty percent of the applicable performance target, respectively. The mitigation fee is capped at $4,000,000 dollars in any year that the performance target is exceeded.*

Any mitigation fees paid would be used to implement emission reduction projects in the area impacted by the excess emissions. The amount of the *mitigation fee is based upon the current and future expected costs of vent gas recovery and treatment equipment needed to mitigate the exceedance of the final annual performance target. It is expected that refineries will implement the procedures and install the equipment necessary to achieve compliance with the performance targets*

Comment 13: There should be no exemptions from mitigation fee payments. High emissions can still result even from facilities that are in compliance with the requirements to be exempted from paying mitigation fees.

Response 13: *PAR 1118 has been revised such that no facility is exempt from paying mitigation fees for emissions exceeding the annual SO_2 performance targets.*

Comment 14: In order to be exempt from mitigation fee payments, a facility must meet emissions standards of 0.25 tons or less of SOx per 1 million barrels of crude throughput. This standard is too low and based on a one-time best achieved emissions level by a refinery.

Response 14: *Under the revised staff proposal, this compliance option is no longer necessary and, therefore, staff has removed this compliance option from PAR 1118.*

Comment 15: The rationale behind calculating the emission level of SOx as a two-year average needs to be explained.

Response 15: *Staff has removed this compliance option from PAR 1118. However, for clarification, calculating emissions for compliance purposes using a two-year average was based on the fact that the frequency of flare events (and emissions) do not constant; they can vary from year to year. An average would smooth out any anomalies.*

Flare Minimization Plan

Comment 16: The Flare Management Plan requirement could be a stand alone rule. The requirement simply duplicates the emission reductions already imposed by limitations on causes of flaring, the performance goals, and the 160 ppm vent gas H_2S limit.

Response 16: *PAR 1118 has been revised to only require a flare minimization plan (FMP) from refineries that exceed the annual SO_2 performance targets. The FMP requirement is a tool to ensure refineries that take appropriate measures to stay below the annual performance targets. Therefore, staff believes the FMP needs to be a part of PAR 1118.*

Comment 17: The requirement to provide in the FMP application a list of all valves, components, or any equipment at any process units venting directly to the flares is extremely punitive and burdensome and serves no apparent useful purpose.

Response 17: *PAR 1118 has been revised to only require P&IDs for each flare system in the FMP. Secondly, staff believes refineries will take the necessary steps, including the installation or modification of vapor recovery and gas treatment system(s) to ensure compliance with the annual performance standards. Therefore, staff believe that submittal of an FMP (with required data and information) is not likely.*

Comment 18: An explanation of policies and procedures to minimize flaring emissions during emergencies, shutdown and startup of *each* process unit should not be required in the FMP application. Since many policies and procedures are not unit-specific and instead have broad applicability, refineries ought to be able to respond to this requirement in a form and manner appropriate to their situation.

Response 18: *PAR 1118 has been revised to require an FMP only from refineries that exceed the annual SO2 performance targets. Also, the information required under a FMP submittal has been streamlined to only include refinery policy and procedures to be used and vapor recovery and gas treatment capacity that will be installed to minimize flaring.*

Comment 19: The district should provide more specific startup/shutdown requirements in order to provide better direction to refineries which will in turn help ensure compliance.

Response 19: *Because of the differences in the way refineries in the Basin are designed and operated and the associated complexities of these operations, as well as safety implications, staff believes that it is best to leave the election of specific procedures relative to shutdown and startup to the refinery operators. It is more appropriate, as PAR 1118 does, to establish a regulatory framework that requires refineries to minimize emissions.*

Comment 20: It is not practical to include in a FMP an estimate of the quantity of vent gas emitted during each occurrence, the duration of each occurrence, the number of occurrences each quarter, and maximum total volume of vent gas being routed to the flares each year is an impractical request. There is concern over the potential negative ramifications for refineries who cannot accurately predict the various aspects related to their future occurrences.

Response 20: *PAR 1118 has been revised to require from refineries that exceed the annual SO_2 performance target to include in their FMP application the policies and procedures as well as gas recovery and treatment systems that will be utilized to minimize flaring and related emissions.*

Comment 21: There should be no exemption for developing an FMP. Instead, both the strict emissions targets of .25 tons of SOx per 1 million barrels of crude processed and an FMP should be required of all refineries.

Response 21: *The latest proposal of PAR 1118 puts greater emphasis on minimizing flare events and emissions through the annual performance targets, which are significantly lower than previously presented at the June 29, 2005 Public Workshop. The 2010 annual SO_2 performance target of 0.7 tons per million barrels of crude oil processed is much lower than the 2.1 tons per year target stated in the 2003 AQMP. Staff believes the proposed performance targets are real, quantifiable, enforceable, and permanent (with the requirement of a mitigation fee for annual exceedances) and are technologically feasible and cost effective. A FMP will only be required from refineries that exceed the annual SO_2 performance targets.*

Comment 22: The level of emissions .25 tons of SOx per 1 million barrels of crude processed is too low to be practicable for refineries to meet. At such a low level, reducing emissions is no longer a viable alternative to submitting an FMP. This emission limit of 0.25 tons/MMBbl is based on the very lowest emissions data from two refineries. The district should take into consideration that even at the refineries that did achieve the aforementioned limit, there will always be year to year fluctuations in emissions.

Response 22: *The version of PAR 1118 presented at the Public Workshop provided refineries a compliance option to request a permit limit of 0.25 ton of SOx per 1 million barrels of crude processed; refineries accepting the permit limit would not be required to submit a FMP. Based on public comment and discussion with the Refinery Working Group, PAR 1118 has been revised to remove this compliance option. PAR 1118 was revised to now require refineries to meet declining performance targets over time and, beginning calendar year, 201~~0~~2, to emit no more than 0.~~7~~5 ton SO_2 per million barrels of crude oil processed per year.*

Specific (Root) Cause Analysis

Comment 23: The 100,000 scf of vent gas or 500 lbs of sulfur dioxide emissions as a threshold for root cause analysis is too low. 500,000scf or 1000 lbs of sulfur dioxide emissions is suggested as a more practical threshold level.

Response 23: *PAR 1118 has been revised to now require a Specific Cause Analysis (SCA) when flare emissions or flow rate exceed any one of the following: 100 lbs of VOC; 500 lbs of SO_x emitted or flaring of 500,000 standard cubic feet of vent gas. Under federal requirements, refineries are required to analyze and report SOx emissions exceeding 500 pounds per release.*

Essential Operational Needs

Comment 24: It is impossible for an operator to foresee in detail all possible essential operational needs. Therefore, the rule should provide pre-defined EON categories with the provision that if a facility encounters a new scenario, the facility has the prerogative to analyze the event, determine if it is and EON and then submit it to AQMD for approval.

Response 24: *Staff has revised the definition of Essential Operational Need in PAR 1118 to now list specific operational or maintenance related activities where due to the quality or quantity, the vent gas cannot be reasonably recovered, treated, used or delivered for sale with existing equipment*

Comment 25: The current definition of Essential Operational Needs disqualifies many scenarios that a refinery could actually identify as an EON. The district, in deciding whether a scenario qualifies as an EON ought to examine not just the technical feasibility of a measure, but also the practicality, cost, and cost-effectiveness. The definition of EON should include such scenarios as fuel gas system imbalances, PRV leakage, and adding fuel gas to vent gas to support its combustion.

Response 25: *In developing standards and requirements, staff conducts technological feasibility and cost effectiveness analyses. The definition Essential Operational Needs in PAR 1118 has been revised to include such scenarios as fuel gas system imbalances, PRV leakage, and venting clean service streams to a clean service flare or a general service flare, and adding fuel gas to vent gas to support combustion.*

Visible Emissions

Comment 26: PAR 1118s provision to require a visual emissions evaluation within five minutes of observing visual emissions on the video monitor is impractical at best, and at worst, dangerous. During emergencies the focus of trained personnel should be on responding to the emergency, not on conducting a visual emissions evaluation.

Response 26: *Staff agrees with the recommendation. PAR 1118 has been revised to require video monitoring with a date and time stamp to determine and record visible emissions from refinery flares*

Comment 27: The requirement to visually monitor is vague and could imply around the clock monitoring. Such a requirement would mean that a facility could be out of compliance if a video monitor appeared to be "unattended" by refinery personnel.

Response 27: *PAR 1118 has been revised to remove that requirement that a refinery visually monitor visible emissions from flares. See Response 26.*

Comment 28: The requirement to operate all flares in a smokeless manner constitutes double jeopardy, as visible emissions are already regulated under Rule 401.

Response 28: *Staff disagrees. Although both PAR 1118 and Rule 401 address visible emissions, they are different standards with different requirements and measurement methods. PAR 1118 requires that flares be operated in a smokeless manner, which is defined as no visible emissions except for periods not to exceed a total of five minutes during two consecutive hours, based on USEPA Method 22. Rule 401 limits the visible emissions into the atmosphere from any single source of air contaminant for a period or periods not to exceed more than three minutes in any one hour to as dark or darker in shade as that designated No. 1 on the Ringelmann Chart or an equivalent opacity, based on USEPA Method 9. Therefore this does not constitute double jeopardy.*

Comment 29: The requirement to operate all flares in a manner with no visible emissions ignores the basic flare design principles such as smokeless capacity vs. ultimate capacity.

Response 29: *Staff understands that vent gas flow exceeding the smokeless capacity may result in visible emissions. PAR 1118 allows visible emissions for periods not to exceed a total of five minutes during two consecutive hours flare will cause visible emissions. Any visible emissions due to exceedances of the flares smokeless capacity are typically due to emergencies and breakdowns. Such visible emissions caused by the incident would be covered by Rule 430 – Breakdown.*

Comment 30: Some threshold Ringelmann number must be specified for visible emissions. If it is not, the smallest wisps of smoke could trigger an NOV or the smallest wisps of smoke could require a "reader" to go out into the field and conduct a visible emissions evaluation.

Response 30: *PAR 1118 allows visible emissions for periods not to exceed a total of five minutes during two consecutive hours. Staff has deleted the requirement that a certified "smoke" reader monitor visible emissions. See Responses 27 and 30.*

Comment 31: The requirement for a PRD survey to be conducted within 90 days prior to a scheduled turnaround is not adequate for turnaround planning purposes. Instead of specifying timing, the rule should specify that the scheduling of any PRD survey should be consistent with the turnaround planning timetable.

Response 31: *Staff disagrees. Maintenance, repair or replacement of defective PRDs is necessary to minimize flare emissions and often can only be corrected during a turnaround. It is now common practice to conduct unit turnarounds every five years. Conducting the PRD survey too far in advance of a scheduled turnaround may not provide the refinery with the knowledge that a PRD is now leaking and in need of corrective action. Staff believes that conducting the PRD survey within 90 days of the turnaround provides the refinery with sufficient time to adjust their turnaround timetable and gives the surrounding community a reasonable expectation that they will not have to experience flare emissions from leaking PRDs for the next five years waiting for the next scheduled turnaround.*

Clean Service Flares

Comment 32: Clean service flares should be exempted from the various requirements of PAR 1118. Their emissions are insignificant and they are already regulated to a certain extent under current Rule 1118.

Response 32: *Staff disagrees. All emissions should be considered in determining whether the facility meets its performance targets. In recognition, however, clean service flares may have a more consistent and typically lower SO2 concentration compared to other flares and are exempt from the daily sampling requirements.*

H2S Limits

Comment 33: The 160ppm H_2S limit for flaring is duplicative of limitations on causes of flaring, the requirements for FMPs, and the performance goals. Furthermore, this limit is an attempt to apply the EPA Subpart J (NSPS) limit to all flaring, an unnecessary rule element as industry has already achieved the emissions reductions contemplated by the AQMP measure. Additionally, Subpart J specifies a 3 hour rolling average, while PAR 1118 specifies no time limit. The AQMD has not demonstrated the feasibility of universal compliance with the 160ppm H_2S limit NSPS-based requirement that is not currently applicable to all flares.

Response 33: *Local refineries currently operate several "NSPS" flares that comply with proposed 160ppm H_2S limit. Staff has determined that three refineries will need to install flare gas recovery and treating systems and other* *refineries may consider expansion of flare gas recovery and treating systems to comply with the annual SO_2 performance targets, which can also be designed to comply with the proposed 160ppm H_2S limit. Staff has concluded that these systems are technologically feasible, achieved in practice and are cost effective (as part of the monitoring and control proposal for PAR 1118. PAR 1118 has been revised to allow averaging over a period of three hours rather than an instantaneous limit. Also, this proposed requirement does not include vent gases resulting from emergencies, shutdown, startup or relief valve leakage. Staff believes that other possible vent gas can be controlled to comply with the H_2S limit as part of the new and expanded recovery and treatment systems*

Comment 34: Because the H_2S limit applies to Essential Operational Needs, refineries needing to install flare gas vapor recovery and treatment systems could be out of compliance with this standard until the control systems are installed.

Response 34: *Staff has revised PAR 1118 to exclude relief valve leakage (due to a malfunction) when determining compliance with the H_2S limit. Staff believe all other essential operational needs, as defined in paragraph (b)(4), can be collected and treated to compliant levels. To allow time to install or expand needed control system(s), staff has revised the compliance date to January 1, 2009.*

Operation Monitoring and Recording Requirements

Comment 35: Six months after Flare Monitoring and Recording Plan approval may be insufficient time to install a calorimeter to analyze emissions.

Response 35: *Staff has revised PAR 1118 to require the installation and operation of a continuous higher heating value analyzer by July 1, 2007.*

Comment 36: The requirement to take a sample within the first fifteen minutes of each sampling flare event presents significant logistical hurdles, and in some cases it is an impossibility.

Response 36: *PAR 1118 requires the use of automated sampler to collect gases to be analyzed for higher heating value and total sulfur. Staff has determined that automated samplers are currently available and are in operation at most local refineries. These automated samplers can be programmed to take a sample 15 minutes after the start of a flare event.*

Comment 37: The requirement for daily sampling is a burdensome and expensive proposition which serves no purpose. There are millions of data points that could be used to develop statistically reliable averages.

Response 37: *Staff believes that increased sampling frequency will greatly increase the accuracy of emission data until the continuous monitors are installed. Many data submitted by the refineries was not measured but rather substituted data based on calculations. The cost of daily sampling and analysis has been included in the cost effectiveness determination for PAR 1118. Staff has determined that PAR 1118, which includes daily sampling, is technologically feasible and cost effective.*

Comment 38: Sampling during a Sampling Flare Event ought to suffice as the daily required sample.

Response 38: *Staff believes that increased sampling frequency will greatly increase the accuracy of emission data until the continuous monitors are installed. Furthermore, the use of data collected during a sampling flare event, such as an emergency, has in most instances, been documented as a value greater than the values measured during a smaller, non-sampling event. However, staff has revised PAR 1118 to allow the use data collected during a sampling event for the required daily sample.*

Comment 39: The time limit on breakdowns and unplanned flare monitoring system maintenance of 48 hours per quarter is not feasible. Often, more time is needed because vendors must be called out for repairs. 160 hours annually has been suggested as a viable option to the 48 hours per quarter limit.

Response 39: *PAR 1118 has been revised to allow flare monitoring system maintenance and repair of up to 96 hours per quarter, which is at least as stringent as Rule 218 – Continuous Emission Monitoring.*

Comment 40: There is no way to determine whether the 14 day per 18 month limit on planned maintenance is feasible, especially given the fact that monitoring systems will now include more components than before and will be more complex. Instead of the aforementioned limit, Rule 218 to should be used to deal with the issues of monitoring system downtime.

Response 40: *Data collected by AQMD on continuous emission monitoring systems (CEMS) does not suggest additional time will be needed. However, staff acknowledges that information on the operation of CEMS for flares is less robust. If the pilot study on the total sulfur analyzer shows a potential need for more than 14 days per 18 months, staff can revisit this provision of PAR 1118.*

Comment 41: PAR 1118 allows the refinery operator to monitor the presence of a pilot flame using a thermocouple or any other equivalent device approved by the Executive Officer. Providing examples of equivalent devices to a thermocouple, such as an IR camera, would be helpful for both facility operators and District engineers.

Response 41: *Staff has determined that thermocouples and video cameras are currently being used successfully to monitor the presence of the pilot flame on flares. However, staff did not want to limit a refinery's ability to propose an alternate measurement technique it believes equivalent. Any alternative(s) by the refinery can be proposed to and analyzed by AQMD staff.*

Comment 42: The requirement to install a flow meter to monitor and record the purge gas and pilot gas flow to each flare has no greater air quality benefit than using engineering estimates. Furthermore the installation of the proposed flow monitoring devices are far more expensive than engineering estimates and may require that the flare involved be out of service.

Response 42: *Staff believes that it is important to establish an accurate emission inventory. Installing flow meters on pilot and purge gas lines will is needed to obtain an accurate measurement of pilot and purge gas to the flares. Flow measuring devices are relatively inexpensive; the cost of this requirement was used in concluding that PAR 1118 is technologically feasible and cost effective.*

Comment 43: The language in (g)(5)(B)(i) is unclear. Does the district mean, "all the gases that are delivered to the flares for combustion must be measured and recorded."? Furthermore, the requirement should specify "vent gases" because there is a need to specifically exclude any assist air or steam for the purpose of insuring clarity.

Response 43: *Yes, Clause (g)(5)(B)(i) clearly states "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: All the gases that are delivered to the flares for combustion must be measured and recovered". To exclude "assist air or steam" from the gas(e) being directed to the flare(s), the refinery will need to demonstrate to the satisfaction of the Executive Officer that assist air or steam does not contain anything that will result in the emission of air contaminant(s). However, the revised definition of Vent Gas excludes assist air or steam injected directly into the flare combustion zone or flare stack via a separate line (not the flare header).*

Comment 44: The requirement for flow monitoring instrumentation placement in clause (g)(5)(E)(i) cannot be justified on the basis of an air quality benefit.

Response 44: *Accurate emission data, which includes flow measure to the flares, is paramount to determining the amount of air contaminants released to the atmosphere. Staff can not determine the air quality benefit without accurate flow data. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in "Evaluation Report on Emissions from Flaring Operations at Refineries", which included a recommendation to improve the measurement of flare vent gas flows. Staff believes that it is important to establish an accurate emission inventory; installing flow meters in representative locations will do just that. As an alternative to relocation, an owner or operator may upgrade the meter with a totalizer to subtract any reverse flow to a flare gas recovery system.*

Comment 45: There is no air quality benefit associated with the requirement in clause (g)(5)(E)(iii) to install an automated flare gas sampling system, a costly and unnecessary investment. Such a sampling system will cost $50,000 to $100,000 according to estimates.

Response 45: *Accurate emission data, which includes higher heating value and total concentration of total sulfur, expressed as sulfur dioxide, of gases directed to the flares, is paramount to determining the amount of air contaminants released to the atmosphere. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in "Evaluation Report on Emissions from Flaring Operations at Refineries", which included a recommended the installation of continuous monitoring systems to measure the higher heating value and the total sulfur gas concentration of the flared gas. Several local refineries have already installed and operate automated flare gas sampling systems. Staff believes that this equipment will improve the logistics of taking samples, especially during an emergency when refinery personnel are not available to manually collect the required sample(s). Staff has determined the installed cost of the automated flare gas sampling system to be approximately $5,000 based on cost information provided by an engineering general contractor who has installed sampling systems at refineries and the AQMD.*

Comment 46: The requirement of installation of Higher Heating Value (HHV) technology is problematic. It is requested that they be pilot tested before they are considered as a requirement for flare system monitoring.

Response 46: *Staff has contacted several petrochemical facilities in Texas and Louisiana where continuous calorimeters have been used for a number of years on flare headers for compliance with USEPA 40CFR 60.18 or Texas regulations. Staff believes, based on those testimonials, that a pilot program is not necessary.*

Comment 47: Procedures to prevent flaring events caused by recurring equipment breakdowns, detailing the adequacy of maintenance schedules for equipment, process and control instrumentation are not necessary and are a requirement that should be dropped. The issue is already addressed by the requirements for Root Cause Analysis. Furthermore, what constitutes a definition of recurring is unclear and no guarantee can ever be made that there will not be recurring breakdowns. The term "adequacy" used in the requirement is also subjective and should be replaced.

Response 47: *PAR 1118 has been revised to streamline the requirements of the FMP and eliminate any redundancy with the "Specific Cause Analysis" (SCA), which replaces the Root Cause Analysis. An SCA is an investigation of the cause of the flare vent where the facility operator also identifies corrective measures to prevent a recurrence of a similar flare event.*

Comment 48: There appears to be a misconception that fuel system imbalances only occur as a result of a temporary interruption of pipeline gas sales. Rather, the interruption of pipeline gas sales is probably one of the least common reasons for fuel system imbalances. There is concern that the fact that fuel gas imbalances are specifically addressed implies that they cannot be claimed as an Essential Operational Need, which they are.

***Response 48*:** *Staff understands that an interruption in pipeline gas sales is not the only situation that may cause a temporary fuel gas imbalance; the loss of a combustion device such as a heater or boiler may also cause this temporary situation. Staff recognizes that there are essential operational needs that must be directed to the flare. The definition of Essential Operational Needs has been revised to include vent gas resulting from temporary fuel gas system imbalance.*

Comment 49: The requirement to specify the schedule and resources that will be used to conduct acoustic and temperature surveys of pressure relief devices is impractical. First, specifying schedules that far in advance, is difficult at best. Furthermore, specifying resources so far in advance serves no useful purpose as resources that complete a particular job at the same high quality are often interchangeable. For instance, contractor A could be replaced by contractor B and the job could be done in the same manner.

Response 49: *PAR 1118 has been revised to remove this requirement.*

Comment 50: The requirement to provide a list of equipment breakdowns during the previous five years that resulted in vent gas being directed to the flare cannot be guaranteed to be met since refineries have not been required to keep records going back five years.

Response 50: *PAR 1118 has been revised to remove this requirement.*

Comment 51: The provision requiring that actions be taken to prevent future breakdown is problematic because "prevent" is an absolute term and there cannot be any assurance that future breakdowns will not occur.

Response 51: *PAR 1118 has been revised to remove this requirement.*

Notification and Reporting Requirements

Comment 52: When an unplanned flare event exceeds a threshold of 100,000 scf of combusted vent gas or 500 lbs of sulfur dioxide emissions, the operator is required to contact the Executive Officer within one hour of the event. This extremely low threshold will result in an excessive number of phone calls to the District. There is also concern that any late, or missed calls could result in NOVs, despite the fact that there are no negative air quality implications.

Response 52: *PAR 1118 has been revised to require the refinery to notify the AQMD within one hour, by telephone, of the unplanned release of 100 pounds of VOC, 500 pounds of SO_x, or 500,000 standard cubic feet of vent gas from a flare. The one hour notification requirement is consistent with Rule 430 – Breakdown Provisions and staff believes it is appropriate in order to conduct timely investigations of flaring events and possible public complaints. The AQMD issues NOVs only after careful consideration of the facts and merits of the failure to meet its' rule requirements promulgated to protect public health.*

Comment 53: The requirement to submit a follow-up report to the Executive Officer within 30 days carries with it the implication that a Root Cause Analysis should also be completed within this time frame, which is an unreasonable request. Furthermore, the requirement will result in resources being re-distributed from areas that have a greater potential for achieving air quality benefits to writing these reports that have no immediate air quality impact.

Response 53: *Staff made the requirement for submittal of the Specific Cause Analysis (SCA) consistent with the deadlines in Rule 430 or Regulation XX Rule 2004 (h) for breakdown reports. If needed, a facility may request an extension of up to 30 additional days for submitting the SCA.*

Comment 54: The term mitigation used in the requirement for Root Cause Analysis implies that mitigation of emissions is a requirement. Clarification is needed on this point to prevent the consequences of the subjective nature of the term.

Response 54: *PAR 1118 requires minimization of flaring during flaring events and any actions taken by the operator with this purpose should be reported in the SCA.*

Comment 55: Facilities are not always able to accurately predict the exact time period of even a planned flaring event, thus making the requirement to notify the district 24 hours prior to such an event difficult at best.

Response 55: *Staff understands that emissions reported as part of notification of such schedule changes are estimated at best in which case the facility should notify the AQMD of the revised planned event date and/or time. However, the facility will have the opportunity to refine these estimates once more information about the events become available.*

Comment 56: There should be clarification provided that demonstrates that the quarterly report required for submittal within 30 days after the end of each quarter is consistent with “standard” certifications such as other District requirements, EPA requirements etc.

Response 56: *PAR 1118 language was revised to be consistent with the certification requirements for quarterly reports in other AQMD rules.*

Comment 57: Because of the low thresholds that define a flare event, 500 pounds sulfur dioxide and 100,000 cubic feet of flare gas, many flare events are likely to be nearly continuous, making the requirement to provide an analysis of each flare event difficult.

Response 57: *PAR 1118 language has been revised to require a more comprehensive Specific Cause Analysis (SCA) for larger flare events 500 pounds sulfur dioxide, 100 pounds VOC or 500,000 cubic feet of flare gas is combusted and a basic investigation to determine the relative cause (emergency, shutdown, startup, turnaround, specific essential operational need, or unknown if undeterminable) where more than 5,000 cubic feet of flare gas is combusted by the flare. Staff believes that these thresholds are necessary to reduce emissions from flares since they will in effect provide operators useful information regarding the use of flares at their facilities.*

Comment 58: Requiring the name of the person who conducted the inspection to be part of the annual acoustical or temperature leak survey for pressure relief devices (PRDs) is not justifiable in any way. Furthermore, the clause, “but not limited to”, which is part of the description of what the report should include ought to be deleted because it is too open ended and will result in confusion and problems later in terms of enforcement.

Response 58: *For the AQMD to effectively review and verify measured and reported data, it is critical that the name of the person(s) conducting the annual inspection of PRDs be recorded. Staff has revised PAR 1118 to remove all "but not limited to" language in the proposed amended rule.*

Testing and Monitoring Methods

Comment 59: Neither calorimeters nor sulfur analyzers have been demonstrated to be viable for flare service and both must be tested in a pilot program before PAR 1118 can include a provision requiring the use of semi-continuous heat content analyzer. Furthermore, the District has not justified the cost in terms of air quality benefits of installing these analyzers systems.

Response 59: *Staff has contacted several petrochemical facilities in Texas and Louisiana where continuous higher heating value analyzers (calorimeters) have been used for a number of years on flare headers for compliance with USEPA 40CFR 60.18 or Texas Commission of Environmental Quality (TCEQ) regulations. Staff believes, based on those testimonials, that a pilot program is not necessary for this type of analyzer. A local refinery will be install and operate a total sulfur (TS) analyzer in March 2006. Staff believes that sufficient data will be collected to demonstrate the effective operation of the TS analyzer well in advance of the July 1, 2007 date when petroleum refineries are required to install and operate this type of analyzer. Staff will make a commitment in the PAR 1118 adopting Resolution to conduct a study of the TS analyzer at the local refinery prior to the requirement going into effect. Accurate emission data, which includes total heating value and concentration of total sulfur, expressed as sulfur dioxide,, is paramount to determining the amount of air contaminants released to the atmosphere. Staff can not determine the air quality benefit without accurate emissions data. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in "Evaluation Report on Emissions from Flaring Operations at Refineries", which included a recommendation to improve the measurement of flare vent gas. The requirement of continuous monitoring implements that recommendation.*

Comment 60: In subdivision (j) Testing and Monitoring Methods (B), the sulfur content of vent gas should be expressed as a reduced sulfur compound rather than as sulfur dioxide.

Response 60: *The 2003 AQMP Control Measure CMB-07 requires a reduction in the sulfur dioxide emissions from flares operated at petroleum refineries and* *related facilities. Therefore, staff has determined that it is appropriate to calculate and report concentration of total sulfur, expressed as sulfur dioxide, in the vent gas as sulfur dioxide.*

Comment 61: There is absolutely no justification for the provision that samples be analyzed by a third-party. It should be acceptable for the sample to be analyzed in a refinery lab that meets District operating standards.

Response 61: *PAR 1118 has been revised to allow AQMD approved laboratories to analyze for higher heating value and concentration of total sulfur, expressed as sulfur dioxide, (reported as sulfur dioxide).*

Comment 62: Under subdivision (k) exemptions, the terms "catastrophic" and "major" are subjective and the language ought to be clarified.

Response 62: *Subparagraph (k)(1)(A) relieves a facility from collecting "grab" samples for higher heating value and concentration of total sulfur, expressed as sulfur dioxide, during a flare event resulting from a catastrophic event including a major fire or an explosion at a facility. Staff agrees with petroleum refineries that safety is paramount; only the facility experiencing a significant flare event and the specific circumstances pertaining to that event knows if it is safe to send in personnel to collect a sample. PAR 1118 has been revised to better define circumstances during which sampling is infeasible or considered a safety hazard.*

Comment 63: Requiring facilities to submit a written document to explain flaring events caused by natural disasters or acts of war or terrorism is pointless, because the District would already be well aware of such events.

Response 63: *Staff believes that, in order to maintain an accurate record, this requirement is appropriate.*

Comment 64: The exemption in paragraph (k)(2) should also include flare sulfur dioxide emissions resulting from interruptions of power supply beyond the refinery's control.

Response 64: *PAR 1118 language has been revised to exclude emissions from power outages, other than due to an interruptible power agreement, from the annual performance target.*

Attachment A:

Comment 65: The District should refrain from specifying the materials of construction, or considering area classifications in a rule. Facilities must always be in control of the aforementioned issues as they are the ones that specify, purchase and operate equipment. This general provision extends to specifics in Attachment A such as installation issues like hot-taps.

Response: 65 *The goals of analytic and monitoring requirements are to ensure that complete, accurate meaningful and verifiable data are collected. In that this requirement contributes to ensuring that an analyzer will not have temperature changes that may compromise its ability to accurately measure flare gas parameters, it is both necessary and within AQMD's purvey. Area classification requirements were selected for harmony with building requirements in the region and to ensure safety of monitoring staff.*

Comment 66: The lower threshold of 0.1 in the velocity range is possibly unrealistic and can certainly not be justified based on any air quality benefits.

Response 66: *The manufacturer of the flow meters used by facilities subject to PAR 1118 has stated that the meters can accurately measure flow as low as 0.1 feet per second. However, staff will include a twenty percent margin to account for any fluctuations due to transient flow. PAR 1118 has been revised to raise the threshold to define a flare event as 0.12 feet per second or greater. As previously stated in Response 46, accurate flow data is necessary to determine emissions and air quality benefit as well as air quality detriment.*

Comment 67: It is assumed that data recorded will be transferred to a Data Collection System (DCS) and stored there.

***Response 67*:** *The assumption is correct and all required records have to be kept by the facility for a period of five years.*

Attachment B:

Comment 68: Assuming that the flow rate is the maximum design capacity of the flare when the maximum range of the flow meter is exceeded is an overly pessimistic assumption which will quickly cause emissions performance goals specified in (d)(1) to be exceeded.

Response 68: *Staff has revised PAR 1118 to allow the operators of facilities subject to this rule to substitute flow data that was not measured using both the maximum and the average flow measured during the previous 20 quarters. Based on flow data collected from 2000 through June 2005, the proposed methodology would capture approximately 97 percent of flow data previously reported. Operators also have the option to demonstrate to the*

AQMD that no flow occurred during the time when the flow meter was non operational through the monitoring of the water seal level associated with the flare or through any other operational parameters and/or other process data. Furthermore, the provisions applicable to the non-sampling events have been revised to allow these facilities to rely on previously measured events rather than relying on data substitution procedures. In addition, staff has committed to evaluate the use of the data substitution procedures by industry during the first year of implementation of PAR 1118 and report back to the Governing Board with any recommendations.

Comment 69: Defining the flow rate at the lower range when the flow rate is below the valid lower range of the flow meter means that a refinery could never use "zero". Without a designation of zero a "Flare Event" as defined would never actually end. This applies to both flow meters and to a combination of flow meters and on/off flow indicator switches.

Response 69: *Flow meters are capable of measuring flows as low as 0.1 feet per second. PAR 1118 has been revised to establish a flare event at 0.12 feet per second or greater. The twenty percent difference between the lower limit capability of the flow meter and what constitutes a flare event is adequate for an operator to discern flow from no flow.*

Comment 70: Using the maximum range of the meter as the assumed flow rate for any missing data is not acceptable. Nothing justifies this use of worst-case assumptions, especially in light of the mitigation fees that would apply if emissions performance goals are exceeded. Instead of just using worst-case assumptions, there should be a provision that considers other factors such as water seals that remained intact.

Response 70: *PAR 1118 has been revised to allow facility operators to demonstrate to the AQMD that operational records, such as water seal level or other approved parameters in the Flare Monitoring and Reporting Plan, that a flare event did not occur. Furthermore, the data substitution provisions of PAR 1118 have been revised and the worst case assumptions are no longer applicable.*

Comment 71: The requirement to fill in any missing data with the measurement of the highest sulfur concentration in the vent gas from the previous year is exceedingly harsh and based on unrealistic assumptions. First, it is unlikely that the peak value from the previous year would always exceed any estimate based on engineering knowledge. Secondly, this requirement could lead to a situation in which the payment of the mitigation fee would be based on fictitious emissions instead of real ones. Instead of this worst-case data use, facilities ought to be able to use another appropriate estimate if the facility provides adequate justification for that estimate's use.

Response 71: *Staff has revised PAR 1118 to allow the operators of facilities subject to this rule to substitute concentration of total sulfur, expressed as sulfur dioxide, data that was not measured using both the maximum and the average concentration of total sulfur measured during the previous 20 quarters. Based on concentration of total sulfur, expressed as sulfur dioxide, data collected from 2000 through June 2005, the proposed methodology would capture approximately 97 percent of total sulfur concentration data previously reported. After the continuous total sulfur analyzers are certified by the AQMD, facility operators also have the option to collect a "grab" sample during the flare event and use that analysis to substitute data for time when the total sulfur analyzer was non operational. PAR 1118 also allows the facility operator the option to demonstrate to the AQMD that total sulfur can be estimated through alternative methods using recorded and verifiable operational parameters and/or process data to be representative of the total sulfur concentration.*

Comment 72: There is no reason why the single highest measurement of concentration of sulfur or heat content in the previous 365 days should be used when it would be more equitable to use an average of the values from the previous year.

Response 72: *See Response 7~~2~~1.*

Definitions

Comment 73: The very low velocity threshold of 0.1 ft/sec that helps define a flare event is problematic because it means that facilities are very likely to have continuous flare events. Part of the problem is that in some flare configurations, vent gases may enter the flare header, pass by the meter and then be recovered by the vapor recovery system before breaking through the water seal. This typically results in flow meter reading greater than .1 ft/sec to as high as about 1.5 ft/sec with no vent gas released to the flare. Therefore, a flare event defined by the presence of flow at a velocity of 0.1 ft/sec would force a recording of a continuous flare even when there is no flow to the flare. Furthermore, flare events indicated by flow monitor signals, which are not verified by on/off meters, water seal monitors, or video monitoring, must be excluded from flare events, as defined. A better definition of flare event is, "FLARE EVENT is any intentional or unintentional release of vent gas to a flare based on positive indications or other instrumentation including, but not limited to, water seal breakthrough, on/off indicators, or video monitoring.

Response 73: *The definition of Flare Event has been revised to address the situations where vent gas is measured by the flow meter but through the use of the water seal, the vent gas is processed by the gas recovery system. The revised definition includes the following language: "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."*

Comment 74: The definition of an emergency should include operational upsets to be consistent with federal rules. A better definition would be: "Emergency, for this rule, means a condition beyond the reasonable control of the owner or operator of a refinery requiring immediate corrective action to restore normal and safe operation, which is caused by any sudden, infrequent, and not reasonably, preventable failure of equipment or of a process to operate in a normal or usual manner, force majeure, act of war or terrorism, or external events beyond the control of the operator. Failures that are caused in part by poor maintenance or careless operation are not emergencies." (Reference: Based on 40 CFR 60, Subpart A 60.2 - Malfunctions) In addition, the current definition of Emergency Service Flare in Rule 1118 includes "emergency process upset condition."

Response 74: *The definition of Emergency was revised to include "not reasonably preventable". However, staff does not believe "process upset" should be included in this definition; specific situations will be listed in the definition of Essential Operational Need". The definitions of Emergency and Emergency Service Flare can not be identical in application since clean service flares and general service flares also process vent gases from emergencies.*

Comment 75: A better definition for "FLARE" is the one in the draft BAAQMD rule (definition 12-12-203).

Response 75: *PAR 1118 language was modified to incorporate elements from the BAAQMD in the definition.*

Comment 76: The definition of "FLARE GAS RECOVERY SYSTEM" would not apply in all cases. The following definition should be used instead. "Flare Gas Recovery System is a system consisting of permitted equipment used to prevent or minimize the combustion of vent gas in a flare."

Response76: *Staff believes the suggested definition is too vague and open-ended.*

Comment 77: The definition of "FLARE MONITORING SYSTEM" is inappropriate with the phrase "including but not limited to." There needs to be a clear understanding between the AQMD and industry of what a flare monitoring system consists of.

Response 77: *PAR 1118 was revised to delete the phrase "but not limited to." The definition of Flare Monitoring System includes higher heating value and total sulfur analyzers, flow meters, and on/off flow indicators.*

Comment 78: The definition of "GENERAL SERVICE FLARE" includes activities, such as tank vapor displacement, blowdowns, and "clean up" which should be included in other definitions and/or in the listing of allowable flaring at Rule 1118 (c)(2)(A).

Response 78: *Staff believes that these activities are within the scope of essential operational need(s) or qualify as startups, shutdowns and turnarounds.*

Comment 79: The definition of "HYDROGEN PRODUCTION PLANT" is overly specific.

Response 79: *Staff believes this definition is appropriate.*

Comment 80: Instead of using the current definition of "NATURAL GAS" the District should consider using an existing definition of "pipeline quality natural gas" from either CPUC or EPA.

Response 80: *Staff believes the current definition of Natural Gas is appropriate.*

Comment 81: The following definition of "PURGE GAS" is better than the current version. "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 and to prevent the formation of an explosive mixture due to ambient air ingress."

Response 81: *The definition of Purge Gas has been revised based on your suggestion.*

Comment 82: The definition of a REPRESENTATIVE SAMPLE ought to be consistent with other requirements such as the specifications for Higher Heating Value and Total Sulfur analyzers.

Response 82: *The proposed amended definition for Representative Sample was modified for consistency with requirements for analyzers.*

Comment 83: In the definition of SAMPLING FLARE EVENT it must be made clear that the refinery must initiate the request.

Response 83: *PAR 1118 language was modified to reflect that a facility is to propose a different Sampling Flare Event threshold for the Executive Officer's approval.*

Comment 84: The definition of SHUTDOWN does not take into account that shutdowns occur for reasons other than maintenance, repair, or replacement of equipment. The following definition is more complete. "Shutdown is the process of stopping the operation of a process unit or piece of equipment for any reason, including preparations necessary for maintenance work."

Response 84: *Staff believes that the suggested definition is too vague and may become a loophole to allow routine flaring.*

Comment 85: A more complete definition for STARTUP is the following. "Startup is the process of initiating and achieving normal operation of a process unit or piece of equipment.

Response 85: *PAR 1118 has been revised to include an expanded definition for startup that takes into account parameters, such as pressure, temperature, feed rate, etc. to characterize normal operation.*

Comment 86: In the definition of TURNAROUND it would be helpful to add language regarding installation of new equipment.

Response 86: Staff *has revised the definition of Turnaround to include "installation of new equipment."*

Comment 87: The definition of VENT GAS does not specifically exclude "assisting air or steam, flare pilot gas and any continuous purge gases." These exclusions must be included in the proposed definition. A more complete definition is the following. "Vent gas is any gas generated at a facility subject to this rule that is routed to, and combusted in a flare, excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

Response 87: *Staff has revised definition of Vent Gas to exclude assist air or steam injected directly into the flare combustion zone or flare stack via a separate line (not the flare header). However, any gas that is generated at a facility subject to PAR 1118 and is directed a flare is considered vent gas.*

MISCELLANEOUS

Comment 88: A flare designed for smokeless flaring at full capacity and designated for emergency use only should not be required to have a video monitor installed for it.

Response 88: *Staff is not aware of any flare that is smokeless over the whole operating range up to maximum design. Even if this existed, there is always the possibility of losing steam injection that could result in visible emission, therefore having a video record is appropriate.*

Comment 89: All current activities and uses of the flare should be considered essential operational needs. Without such designation, facilities planning to install complete vapor recovery and treatment systems in the next few years would face challenges relating to certain requirements prior to their installation of the vapor recovery system.

Response 89: *Staff disagrees with this statement that would effectively allow any flaring to take place and make the rule amendment futile. However, the rule language has been revised to allow more time for these facilities that intend to install additional vapor recover treatment capacity and have affirmed steps toward that goal.*

PRELIMINARY STAFF REPORT COMMENTS

Comment 90: The suggestion that a flare gas recovery and treatment system can prevent temporary fuel gas imbalances is incorrect; such systems are not effective for that purpose.

Response 90: *Staff agrees that such a system would not prevent a fuel gas imbalance, but rather flare emissions may be minimized by the use of this equipment.*

Comment 91: The rule is not necessary since the AQMD Basin is in attainment with the federal SOx standards and flare emissions have already been reduced by 80%.

Response 91: *Staff disagrees. SOx emissions are precursors to particulate matter (PM) emissions and the AQMD is not in attainment for PM 10 (particulate matter less than 10 microns aerodynamic diameter) and PM 2.5 (particulate matter less time 2.5 microns aerodynamic diameter). The reductions achieved to date were voluntary and were achieved primarily through operation procedural changes implemented by the refineries. Furthermore, a close look at the current differences of the recovery and treatment capacity of the various facilities indicates that additional capacity for some facilities is feasible to further minimize flaring and* *associated emissions. There is no mechanism in place that prevents backsliding to previous emission levels. PAR 1118 will make these reductions permanent, real, quantifiable and enforceable and will establish a framework for further reductions.*

Comment 92: It is not fair to assess mitigation fees based on an industry-wide performance, where an individual facility has no control on emissions from a competitor. Also, the standard for an "ultra-clean facility" is not attainable.

Response 92: *PAR 1118 has been revised to require petroleum refineries to achieve a facility-specific declining annual sulfur dioxide performance target. Facilities that exceed the annual performance target are subject to mitigation fees and must also submit a Flare Minimization Plan for public comment and Executive Officer approval. PAR 1118 no longer contains an "ultra-clean" facility compliance option.*

Comment 93: The estimated emission reductions based on 2003 emissions inventory is not appropriate since it does not take into consideration further reductions realized in 2004. Further, the use by the District of the DCF method yields a lower number for cost effectiveness.

Response 93: *Staff acknowledges that flare emissions have trended down and that 2004 emissions are lower than the previous stated baseline year 2003. Since emissions may vary significantly from year to year due to turnarounds and other unforeseen events in petroleum refinery operations, it is appropriate to use a multiple year average as an emissions baseline. The staff report has been revised to average sulfur dioxide emissions and vent gas flow rates for the years 2001, 2002, 2003 and 2004 to establish the baseline for calculating emission reductions and the cost effectiveness of PAR 1118.*

Cost effectiveness analysis is a tool to generate a cost effectiveness factor for a control measure. By comparing the cost effectiveness factors of several control measures with each others, one can acquire knowledge about the costs of each control measure relating to their effectiveness in controlling a particular pollutant. It is necessary to compare cost effectiveness factors of different control measures derived using the same methodology and the same assumptions. The AQMD has been using Discounted Cash Flow Method (with a 4% real interest rate) to determine the cost effectiveness factor for numerous proposed rules since 1995.

Comment 94: The Staff Report should include the CARB Resolution 86-60 for reference.

Response 94: *CARB Resolution 86-60 is included as an attachment to this staff report.*

Comment 95: In contrast with the Bay Area Air Quality Management District (BAAQMD) flare rule, PAR 1118 is far more complex and has duplicative requirements.

Response 95: *BAAQMD has two flare rules: one for monitoring and one for control of flare emissions, whereas PAR 1118 has one rule that includes both these aspects. Moreover, the approach of the two Districts to flares is different, BAAQMD is requiring Flare Minimization Plans while AQMD's PAR 1118 establishes performance targets for controlling and minimizing flare emissions.*

Comment 96: The Staff Report needs to explain the applicability of New Source performance Standards (NSPS) requirements to flares with respect to effective dates.

Response 96: *Staff has clarified in the Staff Report all applicable dates that trigger NSPS requirements for flares (40CFR Subparts A and J).*

Comment 97: Acid gas in the Preliminary Draft Staff Report (PDSR) should be described as "a highly concentrated waste stream of hydrogen sulfide gas (up to 90 percent pure) and sour water stripper gas (about 30 percent pure)" The PDSR incorrectly states EPA's position in the October 2000 Enforcement Letter, which is…"refineries should have adequate capacity at the back end of the refinery to process acid gas".

Response 97: *The description of acid gas was enhanced as suggested. Staff believes that the title of the October 2000 Enforcement Letter summarizes EPA's position that routine flaring is not considered "Good Pollution Control Practice" and it "May violate the Clean Air Act".*

Comment 98: The use of the same concepts in the Consent Decrees that EPA has entered with some refiners used in the amendment of Rule 1118 may represent a duplication of a federal regulations and the AQMD Board must recognize it in its findings upon rule adoption.

Response 98: *Staff disagrees. The Consent Decrees are not federal regulations and they may sunset according to specific clauses in each of them, based on each refinery's compliance record for a certain period of time following the signing of the Consent Decree.*

Comment 99: The statement in the Staff Report that refineries burn "waste gases" in flares is a false assumption.

Response 99: *Staff has revise the staff report and the word "waste" was removed.*

Comment 100: Stating that visible emissions are caused by insufficient steam is inconsistent with the smokeless capacity of a flare, since there are limits to how much steam can be used. The staff report should mention that a facility with a flare smoking for 5 minutes within 1 hour could receive two Notices of Violations, one for violating Rule 401 and one for violating Rule 1118.

Response 100: *Staff agrees that when the smokeless capacity is exceeded there is not enough steam to accommodate the high vent gas flow, but acknowledges that this is due to the limitations in the flare design and a clarification was made in the staff report.*

Assuming that a flare was found having visible emissions in excess of Ringelmann 1 or 20 percent opacity for 5 minutes within 1 hour due to a situation other than a valid breakdown, force majeure or power curtailment beyond the operator's control, only one NOV would be issued with two counts of violating Rule 401 and Rule 1118, respectively. If visible emissions were in excess of Ringelmann 2 or 40% opacity, there would be an additional count for violation of California Health and Safety Code 41701.

Comment 101: The operational status of a flare does not involve having just the pilot lights on and the amount of purge gas used depends on other variables than just the flare design.

Response 101: *The Staff Report has been revised to clarify these issues as suggested.*

Comment 102: Clean Service Flares should be exempt from all requirements except for monitoring and recording as specified in Table 1.

Response 102: *Staff disagrees. All flares have emissions potential and all significant flare events need to be accounted for in the form of a Specific Cause Analysis or a relative cause analysis, as required in PAR 1118. However, a Clean Service Flares is defined as 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. Therefore, based on this definition, a Clean Service Flare would have very low sulfur dioxide emissions, and as such would contribute very little to the annual sulfur dioxide performance target. Clean Service Flares are not required to be monitored with higher heating value or total sulfur analyzers and are not required to have daily vent gas "grab" samples taken. However, the operator must collect grab samples for all sampling flare vents.*

Comment 103 The staff report acknowledges that flares are used as control devices that prevent the release of VOC to the atmosphere, but the rule would prohibit this type of use.

Response 103: *Staff acknowledges that there are flares being used as control devices for VOCs. These flares were granted far in the past and would not be allowed for such use if requested by facilities today since the destruction efficiency for flares varies widely from 70 to 97 percent depending on atmospheric conditions and the quality of vent gas combusted. By contrast, thermal oxidizers are designed with a specific residence time, are able to maintain stable combustion temperatures, which results in destruction efficiencies in excess of 99%, are therefore more suited as control devices for VOCs.*

Comment 104: Excessive steam may lead to incomplete combustion and odors downwind. Adding high BTU gases to a flare to improve the combustion efficiency would be prohibited by the rule.

Response 104: *Staff believes that use of excessive steam may extinguish the flame and result in potentially high volumes of odorous and/or toxic substances being released from a flare. Boosting the BTU content of a vent gas with low HHV to ensure appropriate combustion efficiency is allowed as an Essential Operational Need in PAR 1118.*

Comment 105: Federal Regulation 40CFR60.104 has a 160 ppm limit for H_2S, averaged over 3 hours. There should be mention of AQMD Rules 1123 and 1176 and federal regulations requiring control of VOCs.

Response 105: *The staff report was expanded to include the clarification on the H_2S limit. The other rules mentioned do not apply to the operation of a flare, only to control of VOCs, and therefore will not be discussed.*

Comment 106: The report should clarify that flares prevent the release of raw VOCs to the atmosphere. The report should substantiate any “concerns” that OSHA and EPA have regarding the petroleum industry and any claims made by EJ groups.

Response 106: *The staff report has been revised to clarify these issues.*

Comment 107: Most of the "possible alternatives" suggested for minimizing flaring that are listed in the staff report are speculative and lack any foundation.

***Response 107**:* *The suggested possible alternatives are taken form the “Episodic Release Reduction Initiative” document, issued by EPA on July 5, 2001 as a* *collaborative effort of EPA, the (Texas Commission of Environmental Quality (TCEQ), the Louisiana Department of Environmental Quality (LA-DEQ) in cooperation with 13 petroleum refineries.*

Comment 108: There is an economic incentive besides the environmental benefit for flare gas recovery (FGR), as long as the refinery has adequate storage for the recovered gas, or else it would have to flare it.

Response 108: *Staff agrees and the clarification was made in the staff report.*

Comment 109: Staff seems to have relied on an article in the Oil &Gas Journal to determine the necessary capacity of a flare gas recovery system. The article represents the author's opinion, not necessarily universally applicable guidelines.

Response 109: *Staff has expanded the staff report to include guidelines as stated in API 521 for flare gas recovery system sizing, where it is recommended that the system be sized such that it is able to operate over a "wide" range of dynamically changing flow rates. Thus the opinion expressed in the Oil & Gas Journal article is in agreement with the API guidelines.*

Comment 110: The significant emission reductions already realized suggest that there are limited benefits for amending the rule.

Response 110: *PAR 1118 implements the recommendation of the Governing Board regarding improved monitoring, recordkeeping and recording as well as establishing annual sulfur dioxide, already realized performance targets which will ensure that emission reductions already realized are permanent, real, quantifiable and enforceable and that further reductions are achieved in the future .*

Comment 111: The concept of an alternative to a Flare Minimization Plan is worthwhile; the District should encourage refineries to opt for SOx performance targets.

Response 111: *PAR 1118 has been revised to require petroleum refineries to comply with a declining annual sulfur dioxide performance target of 1.5, 1.0, 0.7 and 0.5 tons per year for calendar years, 2006, 2008, 2010 and 2012 respectively. A Flare Minimization Plan will only be required for petroleum refineries exceeding the annual performance targets.*

Comment 112: There is no need to require continuous HHV analyzers since on average this parameter is expected to be constant.

Response 112: *The fact that, on average, the HHV will be constant was an assumption used to estimate emission reductions. For calculating the emissions of each flare event with accuracy, a continuous monitor is the best option to use.*

Comment 113: The statements by staff regarding the cause of flare events are misleading, are based on tabulated data from the September 2004 "Flare Report" that are inconclusive. In addition, please explain your assumptions in calculating emission reductions that are used for cost analysis and cost effectiveness calculations.

Response 113: *Staff disagrees. The data presented in the Preliminary Draft Staff Report was based on 2003 obtained from the "Evaluation Report on Emissions from Flaring Operations at Refineries" (September 2004), which is a summary of data submitted by facilities to comply with monitoring and reporting requirements of the Rule 1118. The Staff Report has been updated to include data for calendar years 2001 through 2004 to calculate average vent gas flow and emissions from flares. Staff has determined that the average flow and emissions data is most representative data for the random, cyclical operation of the flares. Staff believes that emergencies, startup, shutdown, turnaround and fuel gas balancing events are a significant and determinant event/operation that should have been easily identified and reported to the AQMD. The total vent gas flow and calculated emissions other that sulfur dioxide and the measured total sulfur emissions, calculated as sulfur dioxide are accurate based on flow measurement, sampling, analytical, and published emission factors. Staff has met with two of the three facilities that have been identified in the staff report as needing (projected) additional gas recovery and treatment system capacity. These two "larger" facilities confirmed the need to install four systems totaling 13 mmscf capacity. Staff has determined that the third facility would install a system with 0.3 mmscf capacity. Staff has estimated the size of the systems based on historical vent gas flow. These systems will minimize vent gas directed to the flares which will reduce sulfur dioxide and other criteria air contaminants.*

Comment 114: Some suggested flare controls might have been considered technically feasible; however, practicality, costs and cost effectiveness were not necessarily considered.

Response 114: *The staff report language was modified to clarify that these controls were technologically feasible.*

Comment 115: Refineries that may not have to install flare controls will still incur significant costs for monitoring and other requirements of PAR 1118; in aggregate, complying with the rule will be a significant expenditure.

Response 115: *Monitoring and other requirement costs were included by staff in the cost-effectiveness analysis of the proposed rule. Staff has determined that PAR 1118 is both technologically feasible and cost effective.*

Comment 116: The assumptions made in the staff report for determining cost-effectiveness will need to be evaluated by individual facilities and commented upon. It is unclear whether three or four flare gas recovery and treatment systems are proposed and the number of flow meters for pilots may be triple than that indicated in the staff report.

Response 116: *Staff has estimated that four flare gas recovery and treatment systems would have to be installed at three petroleum refineries; The four systems will minimize vent gases to eight flares that currently are not connected to any gas recovery and treatment systems. Staff's analysis is discussed in Chapter VI – Cost and Cost Effectiveness. The number of flow meters for the pilot gas was assumed to be one meter per flare, located on the natural gas line before it splits in individual lines for each pilot.*

Comment 117: The case study used in the staff report to determine the cost of a flare gas recovery system was related to acid gas flaring. It would not be unreasonable for staff to contact each of the eight facilities subject to the rule to evaluate the cost of necessary expenditures required by the rule.

Response 117: *Staff has conducted interviews with subject facilities to assess compliance with future proposed rule requirements. For better accuracy in estimating costs, staff has expanded its analysis to two additional case studies from the data submitted by two local refineries for the installation and subsequent operation of two flare gas recovery and/or treatment system in 1993 and 2001.*

Comment 118: Staff needs to explain how the necessary size of a recovery system was determined.

Response 118: *The staff report states that for the flare considered for upgrade with a recovery system, the quarters with the highest flow between 2000 and 2003 were selected; then an average daily flow for those quarters was calculated. Based on a review of technical literature on flare design, the capacity of the recovery system was estimated at 2-3 times the daily flow rate.*

Comment 119: It appears that staff may have underestimated some equipment and labor costs; refineries could provide some data in this respect.

Response 119: *Staff used cost information supplied by the refinery in Billings, Montana, as well as the cost data from two local refineries that installed control equipment in 1993 and 2001. Although the systems installed varied in scope and size, the cost of the flare gas treatment capacity was consistent, ranging from $8.32 to $8.77 million per four million cubic feet of gas recovered/treated. Staff will review any cost data supplied by refineries.*

Comment 120: The quoted prices for different pieces of equipment should be provided to refineries for evaluation.

Response 120: *Chapter VI - Cost and Cost Effectiveness lists the cost of control, monitoring and labor. The PAR 1118 Administrative Record contains the actual quotes and facility-specific cost information. Some of this information is considered confidential. Any non-confidential information can be provided to interested parties upon written request.*

Comment 121: When calculating the cost of equipment over time, staff did not factor in adjustments for inflation.

Response 121: *Staff disagrees. The cost of future expenditures was adjusted for inflation.*

Comment 122: Annual costs should include taxes and insurance.

Response 122: *The total installed cost includes taxes and insurance.*

Comment 123: The annual estimated savings due to recovered gas should be based not on the maximum capacity of the compressors but rather on the average flow rate of the gas recovered. Staff needs to explain the assumptions made in calculating the savings.

Response 123: *Staff has revised its analysis to use the annual average flow rate of vent gas recovered through the installation of additional vent gas recovery and treatment systems. Please refer to Chapter VI – Cost and Cost Effectiveness for a discussion on the assumptions used in calculating the cost savings.*

Comment 124: Staff has not clarified the necessity of the rule for ozone attainment.

Response 124: *The proposed rule amendment is necessary since oxides of sulfur (SOx) are precursors to PM10 and PM2.5. Since the rule is designed to minimize flaring and associated emissions, in addition to the SOx reductions, the rule will result in concurrent reductions of other criteria pollutants such as hydrocarbons, oxides of nitrogen and carbon monoxide, all of which are precursors to ozone.*

WRITTEN COMMENTS RECEIVED AFTER OCTOBER 7, 2005

Comment 125: We believe that the best way to protect communities is to require all the refineries to submit a Flare Minimization Plan (FMP), which will be subject to public participation. CBE believes an FMP is the best and most transparent approach to identify unnecessary flaring practices and equipment and procedures that eliminate routine flaring. Performance targets, while important, do not identify unnecessary flaring categories and allow routine flaring within the performance targets.

Response 125: *PAR 1118 establishes a multi-pronged strategy to ensure that flaring and associated emissions are minimized. Therefore, the performance targets should not be viewed in isolation from the other provisions of the proposed amendment. Specifically, PAR 1118 has explicit provisions that would prohibit any unnecessary or so-called routine flaring. The proposed amendment states that no flaring is allowed other than emergencies, startup, shutdowns or essential operational needs. Staff went to great lengths in working with all stakeholders to carefully define all these terms in the rule. PAR 1118 would also require facilities to complete a detailed analysis of larger flare events and to identify the cause of smaller flare events*

In response to the comments received, staff amended its proposal to also require facilities to conduct an audit of their flare gas recovery and treatment capacity; identify past emission reduction efforts and future efforts to further reduce flaring and associated emissions, and to evaluate options to reduce flaring during planned events, such options as slowing the depressurization of vessels, storing vent gases, etc..

In addition to the flaring minimization strategies mentioned above, PAR 1118 establishes annual facility-wide performance targets that seek to incrementally reduce emissions starting 2006 through 2012. These performance reduction targets, which have been recently strengthened and are now designed to exceed the AQMP targets by at least 75 percent, are accompanied by substantial mitigation fees that would be triggered in the event the performance targets are exceeded. The staff proposal also significantly strengthens the emissions data gathering and monitoring procedures of the rule which will significantly improve the emissions data quality and a facility's ability to refine its flare minimization strategy.

Staff has also committed to evaluate the Bay Area Air Quality Management District Rule 12 – Flares at Petroleum Refineries requirement to implement Flare Minimization Plans and the resultant installation of controls and report back to the Governing Board with any recommendations.

Comment 126: In addition, the FMP should require a Best Available Retrofit Control Technology (BARCT) assessment and an audit (list) of equipment, processes and procedures to reduce flaring caused by non-emergency, planned start-ups and shutdowns and flaring events resulting from power curtailments.

Response 126: *As stated in Response 125, staff believes that annual performance targets are more effective than FMPs to reduce flare-related emissions from refinery flares. Regardless, staff has revised its proposal to require each facility to conduct an audit of its flare gas recovery and treatment capacity and identify past and future control actions. Refineries that exceed the annual performance targets are then required to submit an FMP. The required elements of this FMP are nearly identical to the list of elements suggested by the commenter, which includes detailed technical information regarding their flare system, policies and procedures related to emergency and planned flaring, audits of their flare gas recovery capacities, flare gas storage and treating capacities.*

Comment 127: PAR 1118 performance targets need to be significantly lower and a daily limit for both SO_X and VOC should be required to limit the health impact of flaring activities on the community.

Response 127: *The annual performance target has been lowered to 0.5 ton SO_2 per million barrels processed effective January 1, 2012. This revised proposed target is approximately 70 percent lower than the baseline emissions used in the cost analysis for this proposed rule and approximately 75 percent lower than the AQMP Control Measure CMB-07 targets. Also, see Response 125.*

Staff has determined that it is impractical at this time to establish a daily emissions target for SO_2 or VOC because the flares are operated to reduce vent gases resulting, in large part from emergencies, and essential operational needs. These are random events and associated emissions vary significantly. Based on reported emissions data (reductions documented since 1999), refineries have initiated procedures to minimize vent gas releases from shutdowns and startups.

PAR 1118 implements Step II of Control Measure CMB -07 of the AQMP. In addition, to SO_2 reductions, PAR 1118 will also reduce other criteria air contaminants, including VOC. PAR 1118 limits the types of flaring that are allowed, and requires facilities to minimize flaring. To meet the annual SO_2 performance targets, refineries will have to reduce the amount of vent gas directed to their flare; reducing flow to the flare will have commensurate VOC reductions.

However, through the Board Resolution, staff commits to evaluate the feasibility of establishing daily emissions targets and the appropriateness *of the annual SO_2 emission targets and whether refinements to those targets are warranted, and report back to the Governing Board with any recommendations.*

Comment 128: The definition for Essential Operational Needs (EON) must be tightened since it could be used as a loophole by refineries for bad engineering practices. Refineries should demonstrate why these operations are essential.

Response 128: *In developing the proposed definition of EON, staff carefully analyzed which specific operations are essential and can not be reasonably controlled by the facilities subject to PAR 1118. In addition, as suggested, the EON definition has been more clearly delineated to alleviate any potential lack of clarity by requiring AQMD analysis of the EONs for each refinery to determine if they meet the definition of EON.*

Comment 129: Monitoring is a keystone of the proposed rule and should not be weakened. The quarterly emission reports should be made available to the public expeditiously on the District's web site.

Response 129: *Staff agrees and has committed to make these reports available on the AQMD website as expeditiously as possible.*

Comment 130: Notification requirements during planned events and emergencies should be improved since many low-income residents do not have health insurance or adequate health care.

Response 130: *Effective January 1, 2006, PAR 1118 requires refineries to provide a 24-hour telephone service to answer public inquiries about planned and current flare events. Staff has also committed in the Board Resolution to continue to work with industry and community members, and other public agencies to ensure that emergency notification procedures address the community needs.*

Comment 131: A CLEAN SERVICE FLARE is currently defined as a flare that only combusts "clean" gases, such as natural gas, hydrogen gas and/or liquefied petroleum gas, or any other clean gases with a fixed composition vented from specific equipment. The definition of Clean Service Flare should be modified to also include gases that meet the Rule 431.1 – Sulfur Content of Gaseous Fuels requirement of no more than 40 ppm total sulfur content.

Response 131: *Staff disagrees. The original and continuing intent of CLEAN SERVICE FLARE is to limit the combustion of clearly defined clean gas(es) in that specific type of flare. The requirements for clean service flares are less* *than those for emergency and general service flares because the emissions potential is significantly lower for those flare meeting the definition of clean service flare Gases that meet the definition of Rule 431.1 can be refinery gas, which does not have a fixed composition. Therefore, unlike the other clean gases listed in the definition of Clean Service Flare, the composition of refinery gas can vary and therefore, so can the emissions of other combustion contaminants, such as NO_X, CO, PM10 and VOC.*

Comment 132: Hydrogen production plant flares should not be subject to PAR 1118 because, as demonstrated by the quarterly flare reports, they are low SO_X emitters (less than 40 pounds SO_X per year). Based on the reported emissions data, there are significant differences between a hydrogen production plant flare and a petroleum refinery flare.

Response 132: *The purpose of PAR 1118 is to reduce and minimize flaring and flaring emissions from petroleum-related operations. Staff acknowledges that hydrogen production flares are low emitters of SO_2;compared to the refineries. However, flares at hydrogen plants do use refinery gas and do emit other combustion contaminants, such as NO_X, CO, PM10 and VOC, that are in more significant amounts. Hydrogen production plants do use flares to combust vent gases. The requirements for hydrogen production plants are limited to the demonstration of minimizing flaring at this type of facility.*

Comment 133: Subparagraph (c)(1)(D) requires refineries to conduct a Specific Cause Analysis (SCA) when a specific emission or flow rate level is exceeded. Throughout the discussions at the PAR 1118 Working Group Meetings, staff stated SCAs would be required only for those flare events that did not result from a planned operation (shutdown or startup). We request that staff clarify this in PAR 1118.

Response 133: *Staff will revise subparagraph (c)(1)(D) to emphasize that the owner or operator of a facility subject to PAR 1118 will have to conduct a SCA for those unplanned flare events exceeding 100 pounds of VOC, 500 pounds of SO_2, or 500,000 standard cubic feet of vent gas. For those unplanned flare events less than threshold stated above, the owner or operator needs only to state the cause of the lesser flare event.*

Comment 134: We are requesting staff to clarify that under paragraph (c)(3), flaring is only allowed for "planned" shutdowns, "planned: startups and "planned" turnarounds or essential operational needs.

Response 134: Staff disagrees. Operators are required to minimize flaring and then only to flare vent gas resulting from specific operating conditions. The decision/need to shutdown or startup equipment that may result in the need to flare, whether planned or not planned in advance, can be based on petroleum refineries decision to safely operate specific equipment. Staff believes that the declining annual SO_2 performance targets coupled with the progressive mitigation fees and required submittal of a FMP for exceedences of the annual targets and the requirement to identify the cause of smaller flare events and conduct a SCA for larger flare events will require (and provide incentives for) petroleum refineries to minimize all flaring.

Comment 135 To comply with the annual SO_2 performance targets and the requirement to minimize flaring, some refineries will need to install a flare gas recovery and treatment system(s). Paragraph (c)(4) allows refineries that will need to install flare gas recovery and treatment systems on more than two flares until January 1, 2010, to install the control system(s) for only those specific additional flares. Paragraph (c)(5) requires all refineries to comply with the H_2S limit by January 1, 2009. Since the control equipment to comply with paragraph (c)(5) is the same equipment that will be used to comply with paragraph (c)(4), we are requesting that the AQMD extend the compliance date for refineries with more than two flare that need control equipment to January 1, 2010.

Response 135: Staff has revised PAR 1118 to synchronize the compliance dates for paragraphs (c)(4) and (c)(5).

Comment 136: The definition of EMERGENCY in PAR 1118 includes the phrase "poor maintenance." We believe that the phrase poor maintenance is ambiguous and needs clarification.

Response 136: Staff has revised PAR 1118 to clarify that poor maintenance is tied to repetitive flare events from the same equipment that have occurred as a result of the maintenance, or lack of adequate maintenance of that equipment that caused the flare event(s).

Comment 137: The definition of EON includes flaring caused by emergency situations resulting from a process vessel operating pressure rising above the pressure relief valve set point. To ensure the safe operation of process vessels, we are requesting that the AQMD also include in the definition emergency situations resulting from operational temperatures rising above the process vessel temperature set point.

Response 137: *Staff agrees that temperatures greater than the design operating temperature specifications for specific equipment could result in a flaring event which is necessary for continued safe operation of that equipment.*

The definition of EON PAR 1118 has been revised to include "maximum vessel operating temperature set point."

Comment 138: Throughout the process to amend Rule 1118, our discussions on the annual SO_2 performance targets were based on the crude oil capacity; the current rule version references crude processed. We request that this clarification be reflected in PAR 1118.

Response 138: *During the rule development process, industry identified an inequity of using crude throughput versus crude capacity based on a fixed year of 2004 to establish annual SO_2 performance targets. In any one year, any refinery could be conducting a shutdown or turnaround of a major crude processing unit, which could reduce crude throughput for that baseline year reflecting an artificially low baseline throughput for that refinery. Whereas crude processing capacity more accurately allocates refinery emissions based on normal refinery operations. Local refineries are operating at near capacity; therefore, the difference in emissions impact and reductions based on throughput or capacity are minimal.*

Comment 139: Please clarify that for data substitution, a facility can use data from a previous similar event.

Response 139: *Staff has revised the data substitution provisions of PAR 1118 to clarify that a facility can use flow, HHV, and total sulfur data from similar flare events that have previously occurred, can be used for data substitution, with the Executive Officer's approval.*

Comment 140: The terms "relief valve" and "pressure relief device" are used in the definition of EON and in the requirement to conduct an annual leak survey. Please clarify the meaning for each of these terms in PAR 1118.

Response 140: *A relief valve is the all inclusive, general category that includes all valves that are designed and installed for the purpose of protecting equipment from operating pressure greater than design pressure for the safe operation of that equipment. A pressure relief device is a specific type of relief valve.*

Comment 141: Staff included language in the rule that allowed sampling flare events that occurred within 15 minutes of each other to be counted as one sampling event if the facility can show that the events were from a common cause and the same process unit. Similar language should be incorporated in the definition of SAMPLING FLARE EVENT.

Response 141: Staff agrees and has revised the definition of SAMPLING FLARE EVENT as suggested.

Comment 142: The ARB requests that staff revise the definition of ESSENTIAL OPERATIONAL NEED in section (b)(4) to include a mechanism for the District's Executive Officer to approve or reject activities identified by refinery operators as an "essential operational need" and that staff will commit to annually evaluate the continued progress of refineries in the District to minimize their emissions of all pollutants from flares. As part of this evaluation, District staff should provide a summary of the emissions by year by refinery. District staff should use this information to appropriately develop and recommend future amendments to the rule.

Response 142: *Staff agrees. The definition of ESSENTIAL OPERATIONAL NEED has been revised to include language that essential operational need is "an activity determined by the Executive Officer to meet" one of the following (specific listed activities). In addition, staff has committed in the Resolution to review the definition of ESSENTIAL OPERATIONAL NEED and report back to the Governing Board with any recommendations.*

Also stated in the Resolution is a commitment by staff to provide the Governing Board annual status reports on overall industry performance, which will include a summary of the emissions by year, by refinery. As with all AQMD rules, staff will review this and other information to appropriately develop and recommend future amendments to this rule.

Comment 143: The attached letter from the Western States Petroleum Association was received at the end of the comment period. Staff will be prepared to respond to these comments at the Public Hearing.

WSPA

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

Joe Sparano
President

October 25, 2005

Saundra McDaniel
Clerk of the Boards
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765-4178

RE: **<u>Comments of the Western States Petroleum Association on Proposed Amended Rule 1118, Control of Emissions from Refinery Flares</u>**

Dear Ms. McDaniel:

The Western States Petroleum Association (WSPA) is a non-profit trade association representing nearly 30 companies that explore for, produce, refine, transport and market petroleum, petroleum products and natural gas in California and five other western states. Six WSPA members operate petroleum refineries in the South Coast Air Basin, and will be directly affected by the proposed amended rule. As a result, WSPA and its member companies have a direct and substantial interest in this matter.

WSPA has been an active participant with District Staff in commenting on and providing input to the development of Proposed Amended Rule 1118, currently scheduled for consideration by the Governing Board on November 4, 2005. We have worked diligently with the Executive Officer and Staff to develop a rule that attempts to meet the District's objective of continuing to reduce emissions from flaring, without compromising safe and reliable refinery operations.

We are providing this comment letter to facilitate your review of some important issues that are raised by the current rule language. WSPA will also be presenting oral testimony at the hearing and may provide additional written material at that time.

<u>Summary</u>

Flares are essential refinery safety devices whose operations must not be impaired or compromised. In order for flares to operate safely, they must be available for use and employed when necessary, without restrictions or reservations, particularly when hesitation might create safety issues.

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7754 • Fax: (916) 444-5745 • Cell: (916) 599-2716
jsparano@wspa.org • www.wspa.org

Any constraints on using refinery flares for immediate, necessary pressure relief can result in overpressure of equipment and other potentially dangerous operational situations. Events resulting from these situations can cause significant harm to personnel, equipment and the community.

WSPA is concerned that the very low emission limits posed by the rule and the very detailed regulations and consequent penalties will present refinery operators with a difficult paradox – whether to *risk contributing to non-compliance with a District Rule by going without hesitation to the flare, as operator training and plant management procedures typically call for, or to risk personnel safety, plant equipment failure and community impacts by delaying action to avoid violating an element of the new rule.*

OSHA regulations require operators of refineries to define specific emergency procedures that may require the refinery operator to purposely-direct gases to the flare to relieve excess pressure in refinery operating equipment.

Although WSPA believes the District Staff is sincere in its stated intent not to create unintended safety issues through adoption and implementation of PAR 1118, we are deeply concerned that the amended rule as currently proposed can affect safe operations. PAR1118 needs to be reviewed to ensure that it is consistent with applicable OSHA standards governing refinery operations - we need time to work these details out with staff.

Background

Rule 1118 (originally titled "Emissions from Refinery Flares") was adopted in 1998 and required refineries to install sampling systems and flow-monitoring instruments – a relatively new technology, not previously available – on their respective flares. Since installation, these monitoring instruments have provided refineries with a "tool" to measure and manage their respective flare operations.

The resulting management controls[1] enabled the industry to reduce reported emissions of sulfur dioxide (SO_2)[2] each successive year since the start of the monitoring program in CY 2000. As District staff will show, the industry emitted an estimated 7.2 tons/day in 2000. Yet by 2004, the latest full year that data are available, those emissions had dropped by over 87% to 0.96 tons/day.

These dramatic emission reductions were achieved by facilities on the basis that there was both an environmental and economic benefit to reducing emissions – and occurred without regulation. There is reason to believe that proven economic interests and clean air benefits will continue to be strong drivers for refineries to keep flare emissions at these low levels. However, actual flare

[1] In some cases additional equipment was also installed.
[2] Sulfur dioxide is referred to herein because it is the pollutant on which PAR 1118 is focused.

1415 L Street, Suite 600, Sacramento, California 95814
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jsparano@wspa.org • www.wspa.org

emissions may vary from year to year as a function of various factors (e.g., , maintenance and turnaround schedules, emergencies etc.[3]).

After the Board directed staff (in September 2004) to develop a flare control rule, WSPA discussed with many Board Members and Assistants our intent to work in a more cooperative and collegial approach to rulemaking. And, we have done just that.

The intent was to achieve consensus on a rule that would essentially have two primary goals: allow the District to obtain SIP-credit for the emissions reductions already achieved by the refineries; and, take reasonable steps designed to continue those reductions.

Improved Communication During Regulatory Process

Because of dedicated efforts by WSPA, the Executive Officer and District Staff, a more cooperative process has resulted in improved communication. WSPA and the District may at times not agree with each other's viewpoints – but, as a result of the improved dialogue, we both understand better why these differences exist and can focus our collective energies on possible solutions.

Accordingly, many issues have been resolved – and thus will not be discussed in this letter. However, WSPA does have several remaining issues. In fact, some of the unresolved issues were identified at the outset of the rulemaking, as issues that needed to be addressed, and despite best efforts from all parties, remain unresolved. We have shared them with the Executive Officer and the Staff, who have been receptive to our concerns although we clearly still do not agree on how to resolve every one of them.

Issue: Rule definitions, requirements, procedures

WSPA has concerns with the proposed rule, but those concerns stem primarily from the nature of flare operations – flares are both safety and emission control devices, and the need to use them often cannot be predicted by the refineries. Some of our most serious concerns with the rule, and our recommendations to address those concerns, follow:

- **Missing Data Provision/Data Substitution Procedures** - These procedures are required if a refinery cannot obtain data during a flare event. Although vent gas flow monitors are quite reliable, like all equipment, they do have periodic outages and maintenance requirements. While these procedures raise a number of issues, at a minimum, a provision linking missing data provisions to emissions from previous similar events is needed.

  Further, we understand that the rule will require the installation of continuous analyzers[4] for vent gas sulfur content and higher heating value, and there may be some additional time

[3] The frequency and scheduling of turnarounds is determined by each refinery depending upon its needs; however, industry-wide flare emissions decreased throughout the entire five-year period – no patterns of cyclical emissions have been seen.
[4] Because, neither sulfur nor higher heating value analyzers have ever been utilized for refinery flare gas service, WSPA has proposed pilot projects to assess the viability of these analyzers. Candidate sites for these pilot projects

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jsparano@wspa.org • www.wspa.org

when data cannot be obtained. Although the District has included a provision for a refinery to estimate emissions by other means (e.g., process data, engineering knowledge, etc.), these provisions need clarification.

Recommendation: We have suggested that the rule should cite use of engineering judgment to include reference to previous events from the same or similar pieces of equipment. Allowing use of past data will provide a better and more precise estimate of actual emissions than using maximum theoretical values. Implementation of this recommendation will greatly reduce the chances for overestimation of emissions and imposition of mitigation fees, while still improving the District's ability to address community concerns.

- **Essential Operational Needs (EONs)** - Although we believe the staff recognizes both that refinery operations are complex, and that flares serve as emission control devices (per federal and local rules), the proposed definition of EONs does not and cannot cover the entire range of legitimate and "essential" needs. This could impact proven refinery safety and operating practices. Given the complexity of refineries, and the variability in refinery operations, the EON definition should, at a minimum, be revised to recognize that there are a number of situations that cannot be anticipated or adequately described within the strict definition of the term.

- **Process Upsets** - PAR 1118 recognizes that emergencies can occur, and that they may result in the need to flare vent gas. However, PAR 1118 ties "emergencies" to an *equipment failure* (as well as to natural disasters, utility power outages, or acts of war, etc.). WSPA believes that *process upsets* (conditions which are recognized in Federal definitions – e.g., "the failure of a process to operate in a normal manner") must also be included in the definition of "emergency".

  Staff has partially addressed WSPA's concern by including very limited language under EONs. We have responded by sharing additional insights about refinery operations and process upsets with them, and we are looking forward to better resolution of the issue.

- **Clean Up Additional Rule Provisions** -There is need for a continuing effort to clean up additional rule provisions, including definitions, practical operations limits, etc. WSPA members do not have a clear understanding of some rule language.

  For example, the rule appears to require in Flare Management Plans (1118(e)(1)(C)(ii)) "excess gas storage" - implying that there is a need for a refinery to have that capability. However, storing fuel gas has operations and permitting implications and for some refineries, is a provision that is not operationally practical.

Recommendation for all three concerns above: Given that new regulatory language cannot be crafted in such a short time to address these complex issues, implement a break-in/look-back period where definitions, conditions, and details are defined so that a mutual understanding exists. This period could be anywhere from 1 to 2 years, and

have been identified. WSPA expects that a requirement to install these analyzers will be dependent upon a successful outcome of the respective pilot projects.

1415 L Street, Suite 600, Sacramento, California 95814
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would allow all interested parties to understand the scope, implications and impacts of the rule. This implementation/look back period would also allow a comparison of the rule's actual impact with its original intent.

Conclusion

WSPA has been working cooperatively with the District on this rule and recognizes the District's intent to claim SIP-credit for the significant reductions that the refineries have already achieved. However, the requirements of the proposed rule are complex, and some are untested in refinery applications.

Some additional implementation/shakedown period is needed to develop a better understanding of rule requirements, and reach mutual agreement on certain definitions and requirements. In addition, the 2012 emissions limit of 0.5 tons of SO_2 per million barrels of crude capacity is very aggressive, and may have unintended consequences on refinery safety and product supply and distribution. It should not be reduced further.

Inclusion of the recommendations noted in this letter would greatly improve ultimate rule effectiveness and help the District achieve its targeted emission reductions.

We are prepared to continue working with the District's Executive Officer and Staff to achieve targeted reductions in flare emissions without compromising the safety of our refinery operations and personnel, and the communities around our facilities.

Sincerely,

Joe Sparano

Cc: Barry Wallerstein, Executive Officer, SCAQMD

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(916) 498-7754 • Fax: (916) 444-5745 • Cell: (916) 599-2716
jsparano@wspa.org • www.wspa.org

APPENDIX A

REFERENCES

Staff Report for Rule 1118 – Emissions From Refinery Flares, SCAQMD, December 1997

Evaluation of Refinery Flare Emissions at Petroleum Refineries, SCAQMD, September 2004

2003 Air Quality Management Plan, SCAQMD, 2003

U.S. EPA, Petroleum Refinery Initiative

U.S. EPA Enforcement Alert, Volume 3, Number 9 EPA300-N-00-014, October 2000

U.S. EPA, The Episodic Release Reduction Initiative, July 5, 2001

Hydrocarbon Processing, August 2002, pp76 – 80

Oil and Gas Journal, November 23, 1992, pp 70-76

Oil and Gas Journal, December 7, 1992, pp 68-72

Chevron Texaco Letter to William Norton, BAAQMD, February 6, 20030

APPENDIX B

CALIFORNIA AIR RESOURCES BOARD RESOLUTION 86-60

State of California
AIR RESOURCES BOARD

Resolution 86-60

June 19, 1986

RECEIVED
18 1996
STATIONARY SOURCE COMPLIANCE
REFINERY, ENERGY & OCS TEAM

Agenda Item No.: 86-7-2

WHEREAS, Health and Safety Code Section 42701 requires the Air Resources Board (the "Board") to determine the availability, technological feasibility, and economic reasonableness of monitoring devices to measure and record continuously emissions from larger stationary sources, and Section 42702 requires the Board to specify the types of stationary sources, the processes, and the contaminants for which a monitoring device is available, technologically feasible, and economically reasonable;

WHEREAS, pursuant to the Board's direction following consideration of a 1984 petition from Citizens for a Better Environment ("CBE"), the staff has evaluated the availability, technological feasibility and economic reasonableness of continuous emission monitors for oil refinery flares;

WHEREAS, based on its evaluation the staff has recommended that the Board determine that devices which monitor the on/off status of refinery flares are technologically feasible, available, and economically reasonable;

WHEREAS, the Board staff has further recommended that the Board:

Encourage local air pollution control districts in which refinery flares are located to adopt rules requiring refiners to install refinery flare on/off monitors;

Direct the staff to work, as necessary, with industry and the districts to develop rules requiring the use of these devices with workable but standardized definitions of "on" and "off";

Encourage the districts to require, pursuant to Health and Safety Code Section 42303, refiners to provide grab sample composition analyses of flare feed stream gases;

Direct the staff, after sufficient on/off data and coordinated composition data have been collected, to evaluate such data and develop recommendations regarding the development of a Suggested Control Measure for the control of refinery flare emissions if the staff's evaluation indicates that such control is reasonable;

WHEREAS, pursuant to Health and Safety Code Sections 39002 and 40000, the districts have the primary responsibility in California for control of air pollution from nonvehicular sources;

WHEREAS, Health and Safety Code Section 41511 authorizes a district, for the purpose of carrying out its duties, to adopt rules requiring the owner or operator of any emission source to take such action, including installation of continuous emission monitors, as the district finds to be reasonable for determining the amount of emissions from the source;

WHEREAS, Health and Safety Code Section 43203 authorizes a district air pollution control officer at any time to require from a permit holder information which will disclose the nature, extent, quantity, or degree of air contaminants which are discharged by the source for which the permit was granted;

WHEREAS, the California Environmental Quality Act and Board regulations require that no project having significant adverse environmental impacts be adopted as originally proposed if feasible alternatives or mitigation measures are available;

WHEREAS, the Board finds that:

Pressure sensors, optical radiation sensors, and hot wire thermistors have been used at refineries in California to monitor the on/off status of refinery flares to the satisfaction of refinery personnel;

Refinery flare on/off status monitors are presently available in California from commercial vendors and would cost approximately $800 to $2000 for each installation;

Emissions of oxides of nitrogen and oxides of sulfur from refinery flares are currently not being routinely monitored in California, and the magnitude of flare emissions has not been determined accurately because of the technical problems associated with flare emission monitoring;

Records of the frequency and duration of flare operations made by flare on/off monitoring devices, coupled with composition data from analysis of grab samples of refinery flare gas streams, can be combined with existing information about refinery processes and flares to yield improved emissions estimates;

Standardized definitions of "on" and "off" for refinery flare on/off status monitors would enhance the usefulness of the data from such monitors;

The actions recommended by the staff will have no adverse environmental impact;

WHEREAS, the Board has conducted a public meeting to consider the staff recommendations and has received and considered written and oral presentations from any members of the public wishing to comment.

NOW, THEREFORE, BE IT RESOLVED that the Board determines that monitoring devices are technologically feasible, available, and economically reasonable to identify and record continuously the on/off status of refinery flares for the purpose of determining refinery flare emissions.

BE IT FURTHER RESOLVED that the Board encourages local air pollution control districts in which refinery flares are located to adopt rules requiring refiners to install refinery flare on/off monitors.

BE IT FURTHER RESOLVED that the Board directs the staff to work, as necessary, with industry and the districts to develop rules requiring the use of these devices with workable but standardized definitions of "on" and "off."

BE IT FURTHER RESOLVED that the Board encourages districts to require, pursuant to Health and Safety Code Section 42303, refiners to provide grab sample composition analyses of flare feed stream gases.

BE IT FURTHER RESOLVED that the Board directs the staff to report to the Board in six months on the progress of the districts in developing and adopting rules requiring refiners to use on/off status flare monitors and to submit grab sample composition analyses of flare feed stream gases, and directs the staff to report thereafter as appropriate on the implementation and results of flare monitoring requirements.

BE IT FURTHER RESOLVED that the Board directs the staff, after sufficient on/off data and coordinated composition data have been collected, to evaluate such data and develop recommendations regarding the development of a Suggested Control Measure for the control of refinery flare emissions if the staff's evaluation indicates that such control is reasonable.

I hereby certify that the above is a true and correct copy of Resolution 86-60, as adopted by the Air Resources Board.

Harold Holmes

Harold Holmes, Board Secretary