SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Staff Report

Proposed Rule 1118 - Emissions from Refinery Flares

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A. EXECUTIVE SUMMARY

The purpose of proposed Rule 1118 is to gather data on gas flaring operations at petroleum refinery operations to assess the need for, or the level of, any future controls required in order to minimize flare emissions. This proposed new rule is the first step of a two-step approach. The first step will require refineries and other related facilities to monitor gas flaring activities for the amount and composition of gases being flared. This information will be used to refine the emission inventory from gas flares. If the data demonstrates a need to control flaring operations, the second step will be to develop specific control requirements to minimize flare emissions.

All facilities subject to the proposed Rule 1118 are, or will be, subject to the South Coast Air Quality Management District's (AQMD's) Regional Clean Air Incentives Market (RECLAIM) program for both nitrogen oxides (NOx) and sulfur oxides (SOx). However, gas flares are the only combustion sources exempt from RECLAIM and presently not regulated under the total facility emission cap and monitoring, reporting and recordkeeping requirements of this program. Similarly, gas flares are exempt from several other rule requirements such as emission offsets and vent gas sulfur limitation and monitoring requirements.

The air quality objective for proposed Rule 1118 is to enhance the capability of the AQMD to meet state and federal air quality attainment goals by improving the emission inventory and by ultimately minimizing future emissions of all pollutants from flaring activities at petroleum refinery operations.

The types of petroleum refinery operations subject to this rule are petroleum refineries, sulfur recovery plants that recover sulfur compounds from sour water generated by petroleum refineries and hydrogen production plants that produce hydrogen from refinery gas and supply hydrogen for petroleum refinery operations that operate a gas flare. The gas flares are used for the combustion and disposal of combustible gases due to emergency relief, overpressure, process upsets, startups, shutdowns and other operational and safety reasons. Presently, there are eight operating petroleum refineries, one sulfur recovery plant and one hydrogen production plant with a total of 31 existing flares affected by this proposed rule. There are three petroleum refineries currently operating as bulk loading and storage facilities and one refinery not in operation with a total of nine additional flares with the potential to be affected if petroleum refinery operations are resumed.

The following are highlights of the proposed rule:

The owner or operator of a facility subject to this rule will be required to:

- Submit Flare Monitoring and Recording Plan 90 days after adoption and begin monitoring Flares 6 months after decision regarding approval of Plan;
- In the Flare Monitoring and Recording Plan, classify Flares as Clean, Emergency or General Service and propose any alternative sampling program, if any;
- Conduct limited monitoring/recording for Clean Service Flares, but more extensive monitoring/recording for Emergency and General Service Flares, respectively;
- Determine Pilot and Purge Gas quantity and quality;

- Continuously monitor Vent Gas quantity and periodically sample for sulfur and BTU (during Recordable Flare Events); and,
- Calculate and report criteria pollutant emissions quarterly.

AQMD staff has made a determination that there are no significant environmental impacts associated with proposed Rule 1118

B. STATEMENT OF FINDINGS UNDER THE CALIFORNIA HEALTH AND SAFETY CODE

Before adopting, amending or repealing a rule, AQMD is required by the Health and Safety Code to adopt written findings of necessity, authority, clarity, consistency, non-duplicity and reference, as defined in the Health and Safety Code Section 40727. The findings are as follows:

Necessity - The AQMD Governing Board has determined that a need exists to adopt the proposed Rule 1118 to gather data on flaring operations at petroleum refinery operations to improve the flare emission inventory in order to assess the need for, or the level of, any future controls required in order to minimize flare emissions.

Authority - The AQMD Governing Board obtains its authority to adopt, amend or repeal rules and regulations from California Health and Safety Code Sections 40000, 40001, 40440, 40441, 40463, 40725 through 40728.

Clarity - The AQMD Governing Board has determined that proposed Rule 1118 is written or displayed so that its meaning can be easily understood by persons directly affected by it.

Consistency - The AQMD Governing Board has determined that proposed Rule 1118 is in accordance with existing statutes, court decisions, federal or state regulations.

Non-Duplication - The AQMD Governing Board has determined that proposed Rule 1118 does not impose the same requirement as any state or federal regulation, and the proposed rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the AQMD.

Reference - The AQMD Governing Board by adopting this regulation is implementing, interpreting or making specific the provisions of Health and Safety Code Sections 40001, 40440(a) and (c), and 40910 et seq., (California Clean Air Act).

Pursuant to Health and Safety Code Section 40920.6, prior to adopting rules or regulations to meet the requirement for best available retrofit control technology (BARCT) pursuant to

Sections 40918, 40919, 40920 and 40920.5, or for a feasible measure pursuant to Section 40914, AQMD is required by the Health and Safety Code to adopt written findings that identify one or more potential control options which achieves emission reduction objectives, determine the cost-effectiveness of each potential control option and determine the incremental cost-effectiveness of potential control options. Proposed Rule 1118, at this time, does not implement the requirements of BARCT or any other feasible measures. Therefore, Health and Safety Code Section 40920.6 does not apply to proposed Rule 1118. The findings are as follows:

Potential Control Options - The AQMD Governing Board has determined that proposed Rule 1118 only requires the monitoring, recording and reporting of gas flaring activities and emissions at petroleum refinery operations and does not consider any control options.

Cost -Effectiveness - The AQMD Governing Board has determined that proposed Rule 1118 only requires the monitoring, recording and reporting of gas flaring activities and emissions at petroleum refinery operations, therefore, a cost-effectiveness determination is not applicable.

Incremental Cost-Effectiveness - The AQMD Governing Board has determined that proposed Rule 1118 only requires the monitoring, recording and reporting of gas flaring activities and emissions at petroleum refinery operations, therefore, an incremental cost-effectiveness determination is not applicable.

C. BACKGROUND

The purpose of proposed Rule 1118 is to monitor the quantity and composition of gases flared at petroleum refinery operations in order to improve the flare emission inventory and to assess the need for, or the level of, any future controls required to minimize flare emissions. The existing emission inventory is not representative of actual emissions and the emission inventory from these flares can be enhanced and refined based on the data collected and reported.

Flare Equipment and Operation

Flares are used extensively in the petroleum industry to burn and dispose of waste or excess combustible gases that are generated as part of the production processes or during a process upset or other situations. Flares are also used as safety devices to reduce the potential for fires and explosions due to unburned gaseous hydrocarbon releases. 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 located near the ground level in a shrouded space. 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 nitrogen oxides, sulfur dioxide, carbon monoxide, and particulate matter, in addition to the release of hydrocarbons, 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.

A flare must be kept in an operational status whenever the system it serves is in operation. Therefore, the pilot burners are kept on at all times. A stream of combustible gas, called purge gas, is also continuously pumped through the pipes and into the flare to prevent air from entering the flare header and creating an unsafe explosive mixture of air and hydrocarbons. Depending on the flare design, 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 is a continuous source of emissions.

In a refinery setting, a gas flare may be installed for a single purpose serving 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 from a piece of machinery to the disposal of large quantities of gases during an emergency. Therefore, depending on how a flare is designed and used, the level of details needed to quantify emissions and the equipment used to collect such information may vary significantly. In order to cope with this situation, the proposed rule classifies the flares 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. This type of flare would require the least amount of information to determine the emissions from flare events. 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 complicated and, perhaps, the most common flare configuration is the general service flares. In addition to the services described above, many flares in a refinery are also used to dispose of gases from routine or non-routine operations including purged or waste products, non-emergency releases of excess pressures, venting of storage tanks or wastewater sumps, and equipment leaks, etc. Due to the complexity of these types of flare configurations, the amount of information needed to estimate emissions is more extensive.

Rule Development History

Reducing emissions from petroleum refinery operations was originally conceptualized and formalized in the 1982 Air Quality Management Plan (AQMP) as Measure A15. This measure has been carried over through subsequent AQMPs and is now Control Measure #97CMB-07 in the 1997 AQMP. 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.

In 1984, the Citizens for a Better Environment (CBE) petitioned 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 required substantial development before they would be ready to use and be relatively inexpensive.

In 1986, based on the study and public testimony, 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. 86-80. 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. 86-80. 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 odor complaints due to 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 - Nuisance. These studies and subsequent implementation of recommendations showed that each refinery flare system is complex, unique, and opportunities potentially exist to reduce nuisance problems associated with refinery flare systems.

The Santa Barbara Air Pollution Control District (SBAPCD) adopted Rule 359 - Flares and Thermal Oxidizers 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 (NOx and ROC) and operational limits. The rule also incorporates a Flare Minimization Plan, monitoring, recordkeeping, reporting and source tests for ground flares. However, a review of the staff report indicates that there are no petroleum refinery operations in Santa Barbara similar to the petroleum refinery operations in the South Coast Air Basin and their 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) has a similar rule, Rule 54. Sulfur Compounds, which applies to flares. However, as in the case of the above mentioned 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. Several refineries are operated in Northern California and regulated by the Bay Area Air Quality Management District (BAAQMD). For new flares, BAAQMD requires the use of Best Available Control Technology (BACT). BACT for new flares in BAAQMD requires flares to be only used for emergencies and that routine venting be directed to a fuel gas recovery system. Also, BACT requires staged combustion and 98.0 to 98.5% combustion efficiencies, for elevated and ground flares, respectively. Other than BACT requirements for new flares, the BAAQMD does not have a flare rule. Therefore, proposed Rule 1118 appears to be unique, in that it is the only rule applicable to refinery flares, and is not directly comparable to SBAPCD's Rule 359 or VCAPCD's Rule 54.

Existing Requirements

Currently, all facilities affected by this rule are, or will be, subject to Regulation XX - RECLAIM. However, these gas flares are exempt from Regulation XX - RECLAIM and consequently not subject to the declining emission caps and monitoring, recordkeeping and reporting requirements for each RECLAIM facility. Therefore, flare emissions are not being monitored or reduced accordingly.

In addition, flare emissions are not generally subject to any emission caps or limits under New Source Review (NSR) rules and are exempt from offsets because they are considered as air pollution control systems. New flares are subject to BACT requirements of NSR. However, general modifications to existing flares have not resulted in any new BACT requirements and there are very few new flares built which require BACT. Furthermore, the sulfur content in the gas being burned in flares are exempt from the limits and monitoring requirements of Rule 431.1 with the exception of pilot and purge gases, and thus, not being monitored or controlled. The only rules that presently apply to flares are general prohibitory rules, which are not flare specific, such as Rule 401 - Visible Emissions and Rule 402 - Nuisance.

Emission Inventory

The preliminary emissions inventory for flares at the proposed Rule 1118 affected facilities has been estimated using the AQMD's Emission Fee Billing (EFB) Reports. EFB reports for 1993, January through June 1994, and July 1994 through June 1996 were averaged over the three and one-half year period from all affected facilities and are shown in Table I-1 below.

Table I-1: Reported Average Daily Flare Emissions from All Petroleum Refinery Operations in South Coast

Pollutant	Total (ton/day)
ROG	0.36
NOx	0.35
SOx	1.05
CO	1.95
PM	0.10

The EFB flare emission inventory is based on a derived emission factor in pounds of pollutant per thousand barrels of crude oil processed or tons of sulfur recovered. The derivation was based on EPA AP-42 emissions factors published in December 1977 and assumptions industry and AQMD staff made from available data.

In 1994, one of the refineries in the South Coast conducted a gas flare study with AQMD in order to determine the amount of and potential sources of gases vented to the flare system. The study was intended to evaluate and minimize flare emissions from the subject refinery. The following Table I-2 is a comparison of the January 1, 1994, through June 30, 1994, EFB flare emission data and an estimated emission inventory using current EPA AP-42 emission factors published in September, 1991, along with data collected on gas flaring during the same time frame from the above mentioned refinery gas flare study.

Table I-2: Comparison of EFB Reported Emissions and Emissions Calculated Based on a Flare Study for One Petroleum Refinery

Pollutant	EFB Reported Emissions (tons/6 mo.)	AP-42 Emission Estimate (tons/6 mo.)
ROG	2.91	15.09 - 200.48
NOx	2.84	14.66
SOx	5.35	1078.63
CO	15.65	79.76
PM10	0.80	3.36

As demonstrated in Table I-2, in some cases there may be a wide difference between emissions reported in EFB reports and actual emissions based on monitoring of gases vented to flares. Therefore, there is a definite need to enhance the emission inventory and to obtain more accurate information on flare emissions.

Other Flare Related Impacts

In addition to being the source of emissions, flaring activities are also of concern for their potential to cause visible emissions and odors. Although records of most flare activities are not available at this time, some of these events were recorded by the AQMD in the sources' breakdown reports and the AQMD's investigation reports. Appendix I lists these recorded flare events for the period from February 1992 through August 1997.

The intent of proposed Rule 1118 is to gather data on flaring operations at petroleum refinery operations in order to enhance the refinery flare emissions inventory and to assess the need for, or the level of, any future controls required in order to minimize flare emissions. Following is a brief summary of proposed Rule 1118.

The proposed Rule 1118 consists of the following main sections:

a) Purpose and Applicability;
b) Definitions;
c) Flare Monitoring and Recording Plan Requirements;
d) Operation Monitoring and Recording Requirements;
e) Recordkeeping Requirements;
f) Reporting Requirements;
g) Testing and Monitoring Methods; and,
h) Exemptions.

The following describes each section in more detail.

A. DEFINITIONS

The following key definitions are proposed to clarify applicability and intent of the proposed rule.

Gas flares will be classified into three distinctive categories: clean service, emergency service, and general service. A **clean service flare** is defined as a flare that 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. 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. 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 complicated and, perhaps, the most common flare configuration is the **general service flares**. In addition to the services described above, a general service flare in a refinery is also used to dispose of gases from routine or non-routine operations including venting of purged or waste products, non-emergency releases of excess products, venting of storage tanks or wastewater sumps, scheduled and unscheduled startups and shutdowns of process or air pollution control equipment, and equipment leaks, etc.

A **flare event** is defined as any venting of gases to a gas flare. The emissions associated with any flare event are to be quantified under the proposed rule. However, only “recordable” flare events require sampling and analyses of vent gas for heat contents and sulfur contents, which, together with the measured volume of the vent gas, are used to determine emissions. A **recordable flare event** will initially be defined as a flare event during which the flow rate of vent gases to a flare exceeds 330 standard cubic feet per minute continuously for a period greater than 15 minutes. However, the refineries can propose a different way of defining a recordable flare event for each flare based on site-specific situations. An appropriate mechanism will be required to immediately alert the operator that a recordable flare event has occurred so that a representative sample may be taken in a timely manner.

A **representative sample** is a sample of vent gas collected during a recordable flare event and analyzed for heat content and total sulfur contents. Sampling may be conducted manually or automatically depending on site specific conditions and the refinery's preference. In order to accommodate situations where manual sampling is to be conducted, sampling will not be required for recordable flare events that last less than 30 minutes. Other situations where sampling may not be required include clean service flares for which the vent gas quality is readily predictable, and flaring due to a catastrophic event such as a major fire or an explosion at the facility. In all cases where sampling is not required, the heat content and total sulfur content shall be estimated based on reasonable assumptions in order to calculate and report emissions.

Due to the configuration of a flare system, some sampling connections may be inevitably located in an area where it is unsafe for any personnel to conduct sampling during a specific major flare event. In such case sampling at other locations may be conducted as long as the operator can justify that sampling at the sampling location is unsafe and samples taken at an alternative location is also representative of the flare event. When determining the proposed sampling locations for representative samples, refineries are expected to use good engineering practices so that sampling connections located in potentially unsafe areas may be minimized. On the other hand, a refinery may choose to install automatic sampling devices at these locations to eliminate unsafe sampling conditions altogether.

B. FLARE MONITORING AND RECORDING PLAN SUBMITTAL AND COMPLIANCE SCHEDULE REQUIREMENTS

Proposed Rule 1118 will require affected facilities in operation to submit Flare Monitoring and Recording Plans for AQMD's approval within 90 days after the adoption of the rule. Rule provisions have also been included to accommodate new and non-operating petroleum refinery operations that resume operations. The information in these plans will provide a good understanding of gas flare operations at each facility. The plan will also ensure that the gas flare parameters are properly monitored.

Following is a brief summary of information to be included in each Flare Monitoring and Recording Plan.

1. A facility plot plan showing the location of each gas flare.
2. Type of flare service, (e.g. clean, emergency or general service) and information regarding design capacity, operation and maintenance for each gas flare.
3. Types of pilot and purge gas used, flow rates, and total sulfur content and higher (gross) heating value expected for each type.

4. Drawings and process flow diagrams of the each gas flare and what is connect to each flare (e.g. vapor recovery system, process units).
5. Drawings showing sampling and flow metering or flow indicating device locations.
6. Descriptions of:
   - Vapor recovery systems connected to flares;
   - Existing and proposed flow metering or flow indicating devices for vent gas;
   - Method to verify settings of on/off flow indicators;
   - Analytical and sampling methods or estimation methods for higher (gross) heating value and total sulfur content of the flare vent gas during the interim and subsequent periods;
   - Data recording, collection and management for each flare monitoring system;
   - Method to calculate criteria pollutant emissions for flares and proposed emission factors;
   - Method to alert personnel designated to collect samples that a recordable flare event has started;
   - An alternative definition of a recordable flare event for each flare; and,
   - Alternative sampling program.

C. OPERATION MONITORING AND RECORDING REQUIREMENTS

The owner or operator of a gas flare subject to this rule shall start monitoring and recording in accordance with the Flare Monitoring and Recording Plan, as approved by the Executive Officer and in accordance with the Operation Monitoring and Recording Requirements on or before six (6) months after decision regarding approval of the Flare Monitoring and Recording Plan. In cases where the Flare Monitoring and Recording Plan is denied, or if AQMD determines that a different timeframe is justified, the owner or operator of a gas flare subject to this rule shall start monitoring and recording on a date specified by AQMD and in accordance with the requirements of subdivision (d).

The monitoring and recording requirements of this rule shall be applicable during periods of breakdowns associated with process equipment or any other systems or equipment that are vented to the flares. There are special provisions contained in the proposed Rule 1118 which covers periods of breakdown, unplanned maintenance, or planned maintenance for the actual monitoring and recording equipment used as part of the flare monitoring systems. Any continuous flare monitoring system will be required to be maintained in good operating condition at all times when the flare unit that it serves is operational. The exceptions are:

- A cumulative 48 hour period per quarter for each reporting period to allow for any breakdown and/or unplanned system maintenance; and,
- 14 days per 18 month period for planned maintenance, provided that a written notifcation is given to AQMD prior to, or within 24 hours of, removal of the continuous monitoring system from service that explains the reason for maintenance and the methods that will be used to determine emissions.

Affected facilities will be required to begin monitoring and recording the operational parameters of the gas flare within six months of decision regarding approval of the Flare Monitoring and Recording Plan or other period as approved by the AQMD. The following Table II -1 shows the monitoring and recording requirements.

TABLE II-1

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

1. Standard Cubic Feet Per Minute.
2. All flow meters, flow indicators and recorders shall meet or exceed the minimum specifications in Attachment A.
3. Higher (Gross) Heating Value in British Thermal Units per Standard Cubic Foot.
4. Sample shall be taken within 30 minutes of the start of each flare event. If the flare event is over in less than 30 minutes, estimation may be used instead of a representative sample.

A facility may be allowed to use an alternative sampling program for recordable flare events for each individual flare during the initial six to nine months of interim monitoring and recording. Approval will be based upon a review of proposed Quality Control/Quaility Assurance procedures that will be used to determie the correlation between standard CARB and AQMD methods and proposed alternative methods such as colorimetric methods. This interim period of monitoring and recording will consist of the following:

- Flare vent gases will be sampled and analyzed weekly using standard ASTM or AQMD methods and colorimetric methods which may coincide with a recordable flare event, if any;
- One additional recordable flare event, if any, will be sampled and analyzed each week using standard ASTM or AQMD methods and colorimetric methods;
- All recordable flare events that are a result of a process unit shut down will be sampled and analyzed using standard ASTM or AQMD methods; and,
- All other recordable flare events will be sampled and analyzed in accoradance with approved alternative testing and monitoring methods.

After the initial six months period of monitoring and recording, the owner or operator of a gas flare may request a change in the vent gas sampling requirement for recordable flare events and/or propose alternative criteria for determining a recordable event based on monitoring data, provided the owner or operator of the gas flare can demonstrate, and obtain written approval of the Executive Officer that an alternative vent gas sampling and/or alternative criteria for determining a recordable event is adequate to determine the quality of vent gas(es) and to calculate emissions from all such flare events. Likewise, the Executive Officer may revise alternative vent gas sampling and/or alternative criteria for determining a recordable event if it is determined they are not adequate based on monitoring data or other information to determine the quality of vent gas or to calculate emissions.

A flare monitoring system will be allowed to measure and record the operating parameters of more than one flare provided that: all the gases being measured and recorded are delivered to the flare(s) for combustion; and, if the flare monitoring system is used to measure and record the operating parameters for emergency service flares, as well as general service flares, the flare monitoring system shall consist of a continuous vent gas flow meter and recorder that meets the requirements specified in Attachment A of the rule.

D. RECORDKEEPING AND REPORTING REQUIREMENTS

Affected facilities will be required to record the gas flare parameters specified above and submit a quarterly report within 30 days after the end of each quarter. The quarterly report will include:

- The flare operating information required to be monitored and recorded in paragraphs (d)(3), (d)(4) and (d)(5) of the rule;
- Daily and quarterly criteria pollutant emissions from each flare along with the information used to calculate the emissions;
- A complete description of assumptions used to determine heating value and sulfur content for cases where a sample is not collected and analyzed;
- Flare monitoring system downtime and an explanation of the reason for it; and,
- Copies of written notices for all reportable air releases related to any flare event, as required by 40 CFR, Part 302 - Designation, Reportable Quantities, and Notification and 40 CFR, Part 355 - Emergency Planning and Notification, if applicable.

All records of monitored data and information shall be kept at the facility for a period of two (2) years and made available to AQMD upon request.

E. TESTING AND MONITORING METHODS

This rule allows either ASTM or AQMD methods be used to determine the higher (gross) heating value and total sulfur content of pilot purge or vent gas. Alternative test methods may be used if it is determined to be equivalent and approved in writing by the Executive Officer, or the Executive Officer, the California Air Resources Board and the U.S. Environmental Protection Agency (EPA) if the rule is subsequently submitted to CARB and EPA for State Implementation Plan approval. The higher (gross) heating value of the gases shall be determined by ASTM Method D 2382-88, ASTM Method D 3588-91 or ASTM Method D 4891-89. The total sulfur content shall be determined by AQMD Method 307-91 or ASTM Method D 5504-94. These methods will be required to be conducted by an AQMD approved lab or by a lab owned and operated by the affected facility provided that:

- Prior written approval of QA/QC and standard operating procedures; and,
- All analytical reports are signed by the facility official responsible for analytical equipment to certify the accuracy of the reports.

This rule also allows for an alternative sampling program during the inital interim six to nine month period commencing from the start of monitoring and recording to determine total sulfur and BTU content of vent gas for recordable flare events. Colorimetric analysis is a simple and cost effective method that could potentially be used to determine hydrogen sulfide, and possibly through development of a correlation, total sulfur content. The results of colorimetric analysis and ASTM or AQMD methods would be used to establish a correlation to calculate SO_2 emissions. Alternative methods to determine BTU content could be accomplished by the use of an ultrasonic flow meter that is equipped to determine average molecular weight of the gas. A correlation could be established between the molecular weight determined by the flow meter and the results of ASTM or AQMD methods. This correlation would be used to calculate NOx and CO emissions. An alternative sampling program would facilitate a relatively representative method to calculate emissions during the initial interim monitoring and recording period and to establish appropriate thresholds for recordable flare events at a reasonable cost.

Where applicable, the continuous monitoring systems certified under the RECLAIM program may be used to replace and/or supplement the test methods indicated above.

F. EXEMPTIONS

If sampling of vent gas cannot be conducted due to a catastrophic event such as a major fire or explosion, calculation methods may be used to determine emissions provided the following information is identified: the cause of the flare event; process systems involved; date and time event started and duration; and, any other information related to the type of vent gas that is necessary to calculate emissions.

If sampling constitutes a safety hazard to the sampling personnel at a sampling location approved in the Flare Monitoring and Recording Plan during the entire flare event, a sample will be required to be collected at an alternative location where it is safe. It will be up to the owner or operator to demonstrate that the sample collected at an alternative location is representative of the flare event.

Monitoring of refinery gas flare operating parameters in the South Coast Air Basin has not been mandatory. There are only limited monitoring activities as shown in Appendix II - Summary of November 1995, Information Gathering Survey. Previous attempts to monitor refinery gas flare parameters with thermal conductivity and dispersion flow meters met with limited success due to the high costs of maintenance, limited range and lack of accuracy. Gas flares at petroleum refinery operations in the South Coast Air Basin experience extremely large range of flow rates of varying gases such as hydrogen and heavier hydrocarbons which can interfere with the proper operation of conventional thermal conductivity and dispersion flow meters. Past technology could not meet the requirements necessary to accurately monitor these flow rates. In order to accurately and safely measure gas flare flows, the flow meters should be relatively non-intrusive, accurate over a large range of flow rates and require only a reasonable amount of maintenance. A review of current flow metering technology has found that certain technologies exist which can meet the requirements to safely and accurately measure flare gas flow rates. One such technology is the use of ultrasonic technology and is briefly described below.

Ultrasonic flow meters that measure flow rate of fluids utilize two different technologies: Doppler; and, transit time. Ultrasonic flow meters that utilize the Doppler technology are more suitable for measuring the flow rate of liquid. Ultrasonic flow meters that utilize transit time technology are suitable for measuring the flow rates of gases. It uses two ultrasonic transducers located in the gas flow, each of which is capable of both sending and receiving ultrasonic pulses. Electronic circuits detect and measure the time it takes for the ultrasonic pulse to travel from one transducer to the other. A pulse traveling in the direction of the flow arrives at the opposite transducer in a shorter period of time than a pulse traveling against the flow. The flow velocity of the gas is determined from the time difference. These flow meters presently have an operating velocity range of 0.1 to 275 feet per second (ft/s) with an accuracy of plus or minus five percent over the range of 1 to 275 ft/s.

The ultrasonic meters are used throughout the United States and worldwide to measure flared gas flow rates. There are three (3) facilities where they use such meters in California for petroleum operations with at least four (4) such meters used at a petroleum refinery. Appendix VI - Partial List of Installed Ultrasonic Meters, shows a table of units that are currently being used at refineries, oil and gas production and petrochemical facilities in other states and worldwide.

Appendix IV - Telephone Survey of Ultrasonic Flow Meter Users, provides a table summarizing telephone conversations with seven facilities that are currently using ultrasonic flow meters on elevated gas flares. There were a total of 48 meters installed with a range of one to ten years of operating experience. The installed cost per meter ranged from $22,000 to $50,000 with an average cost of $40,000. Typical reasons why ultrasonic meters were installed were: to obtain information on flaring activities; to reduce flaring activities which resulted in saving product and money; anticipation of upcoming rules and regulation; and, required by the local Air Pollution Control agency. Facilities have claimed to have the same flow meters in service up to seven years without experiencing any significant corrosion or erosion related problems or any significant hydrocarbon deposits that would affect proper operation.

Monitoring and recording of vent gas parameters are specified in Rule 1118, Attachment A - Flare Monitoring System Requirements. The components of each flare monitoring system must meet or exceed the minimum specifications listed below. Components or a combination of components with other specifications may be used provided the owner or operator of a gas flare can demonstrate that the specifications are equivalent and has been approved by the Executive Officer.

1. Continuous Flow Measuring Device

   The volumetric flow measuring device may consist of one or more flow meters, and, as combined, shall meet the following specifications.

Velocity Range:	1-250 ft/sec
Repeatability:	± 1% of reading within a flow velocity of 0.5-100 ft/s
Accuracy:	± 5% of reading over flow range of 1-250 ft/s
Installation:	Applicable AGA, ANSI, API, or equivalent standard; hot tap capability
Flow Rate Determination:	Applicable AGA, ANSI, API, or equivalent standard

   The volumetric gas flow rate, corrected to 1 atmosphere pressure and 68 °F, must be determined and recorded on a continuous basis.

2. On/Off Flow Indicator

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

3. Data Recording System

   All data as generated by the above flow meters and the on/off flow indicators must be continuously recorded by strip chart recorders or computers.

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

A. EMISSION IMPACTS

Proposed Rule 1118 requires monitoring of flaring operations in order to better estimate flare emissions, and is not designed to reduce emissions. However, emission reductions could potentially occur due to better monitoring and management of flare operations as a result of implementing the proposed rule. Monitoring of flaring operations would provide affected facilities with data and information that may allow the facility operators to identify the sources of the flare vent gases and subsequently eliminate or reduce the gas flow. In addition, the data and information may also become a tool by which the facility operator may use to better manage and improve the overall facility efficiency. As such the number of flare events and their associated emissions may be reduced.

Emission Inventory

The preliminary emissions inventory from flares for proposed Rule 1118 affected facilities has been estimated using the AQMD's Emission Fee Billing (EFB) Reports. Table IV-1 below shows each EFB reporting period emissions for all affected facilities on a ton per day basis for a period from 1993 through June 1996 and a ton per day average over the three and one-half year period.

Table IV-1: Reported Daily Flare Emissions from All Petroleum Refinery Operations in South Coast

Pollutant	1993 (ton/day)	1994[1] (ton/day)	1995[2] (ton/day)	1996[3] (ton/day)	Average (ton/day)
ROG	0.37	0.36	0.35	0.37	0.36
NOx	0.36	0.35	0.34	0.36	0.35
SOx	0.68	0.67	0.65	2.19[4]	1.05
CO	1.99	1.95	1.90	1.97	1.95
PM	0.10	0.10	0.10	0.10	0.10

1 1994 emissions based on January through June 1994.
2 Based on EFB data submitted for July 1994, through June 1995.
3. Based on EFB data submitted for July 1995, through June 1996.
4. SOx emission factor changed to 7.6 lb SOx/ton sulfur recovered/yr.

The above reported flare emission inventory is based on a derived emission factor in pounds of pollutant per thousand barrels of crude oil processed. The derivation was based on EPA AP-42 emissions factors published in December 1977 and assumptions AQMD staff made from available data in 1980.

In 1994, one of the refineries in the South Coast conducted a gas flare study with AQMD in order to determine the amount of and potential sources of gases vented to the flare system. The study was intended to evaluate and minimize flare emissions from the subject refinery. Flare vent gas flow rates and total sulfur content were monitored and recorded. The following Table IV-2 is a comparison of the January 1, 1994, through June 30, 1994, EFB flare emission data and an estimated emission inventory using current EPA AP-42 emission factors published in September, 1991, with the data generated during the same time frame from the above mentioned refinery gas flare study.

Table IV-2: Comparison of EFB Reported Emissions and Emissions Calculated Based on a Flare Study for One Petroleum Refinery

Pollutant	EFB Reported Emissions (tons/6 mo.)	AP-42 Emission Estimate (tons/6 mo.)
ROG	2.91	15.09 - 200.48[1]
NOx	2.84	14.66
SOx	5.35	1078.63[2]
CO	15.65	79.76
PM10	0.80	3.36[3]

1. AP-42 emission factor for total hydrocarbons is 0.14 lb/10^6 Btu for the low end. The emissions for the high end are estimated using an emission factor of 0.93 lb/10^6 Btu, which is calculated based on a DRE of 98% and an inlet fuel heat content of 21,500 Btu/lb.
2. SOx emissions are based on total sulfur content of vent gas.
3. PM10 emission estimate based on refinery gas combustion emission factor of 21 lb/10^6 scf and assuming 100% of total PM is PM10.

As demonstrated in Table IV-2, in some cases there may be a wide difference between emissions reported in EFB reports and actual emissions based on monitoring of gases vented to flares. Therefore, there is a definite need to enhance the emission inventory and to obtain more accurate information on flare emissions.

Depending on the refinery vapor recovery and flare systems designs and capacities, certain refineries may have the need to utilize flaring operations in routine or emergency conditions. Table IV-3 is a comparison of maximum refinery gas production, vapor recovery system (VRS) capacities and flare system capacities gathered from four refineries by AQMD's Refinery Inspectors and does not include the sale of excess refinery gas.

Table IV-3: Comparison of Refinery Gas Production, VRS Capacity and Flare Capacity

Facility	Refinery Gas Production (MMSCF/D)	VRS Capacity (MMSCF/D)	Flare Capacity (MMSCF/D)
1	43.50	1.35	647
2	3.81	1.38	53
3	25.00	5.59	124
4	68.12	10.40	864

Table IV-3 shows that the potential of flaring operations in routine conditions emissions definitely exists, especially in the case where a refinery that sells refinery gas to another source can no longer do so.

Other Flare Related Impacts

In addition to being a source of emissions, flaring activities are also of concern for their potential to cause visible emissions and odors. Although records of most flare activities are not available at this time, some of these events were recorded by the AQMD in the sources' breakdown reports and the AQMD's investigation reports. Appendix I lists these recorded flare events for the period from February 1992 through August 1997. Some of the observations from these records are discussed below.

1. Emissions indicated on the list are those estimated and reported by the facilities. Regulations such as 40 CFR, Part 302 and Part 355 require an estimate and report of the amount of release into the atmosphere when the amount exceeded certain thresholds (e.g., 500 lbs for SO_2). AQMD rules, including Rules 430 and 2004(i), also require emission estimate and reporting when a equipment breakdown has caused excess emissions over the rule or permit limits.

2. While not all of the flare events result in significant emissions, some do have the potential to emit a large amount within a relatively short period of time. The most obvious examples from this list are SO_2 emissions during equipment breakdowns, process upsets, or emergencies.

3. Flare events can cause significant emissions of particulate matters and odorous substances such as sulfur compounds, ammonia, and hydrocarbons. These types of emissions can result in public nuisance, but their amounts of emissions have previously not been quantified and reported in all cases.

Refineries in this region have indicated that they have significantly reduced flare events over the past decades for reasons primarily due to (1) plant efficiency improvement and modernization, and (2) public nuisance prevention and community relation improvement. Nevertheless, there is a need to better estimate and understand the flare emissions. The proposed Rule 1118 will establish the monitoring requirements necessary to improve our understanding of flare emissions, and at the same time, may result in improved flare management strategies for affected sources.

B. COST IMPACTS

Proposed Rule 1118 is the first step of Control Measure #97CMB-07, which only requires flare operations to be monitored and emissions analyzed in order to determine if any controls should be required as Step 2 of the Control Measure. Therefore, there is no requirement under the State Law to conduct cost analysis for this rule at this time. However, staff has conducted a cost analysis and received many comments regarding the initial cost estimate for implementing the proposed rule during and subsequent to the public workshop held on June 25, 1996. Staff has since re-evaluated the situation and the approach for the cost estimates. In addition to the cost data provided by main suppliers of the monitoring equipment and contractors, staff gathered data for actual installed system costs from a refinery located in California, as well as the estimated overall project costs conducted by one of the local refineries in preparation for implementation of the proposed rule. As a result, staff has significantly revised the cost estimates, the detail of which is shown in Appendix V - Cost Analysis.

The overall expected potential and maximum potential cost of implementing Proposed Rule 1118 is shown in Table IV-4 below. The maximum potential cost is estimated to be $4,139,615 per year, which includes the annualized capital costs and the annual operation and maintenance costs. This estimate is based on the following assumptions:

1. All the 10 operating facilities and four currently non-operating facilities will implement the rule upon rule adoption.

2. All facilities will install a flare monitoring system that meets the requirements for a general service flare regardless of the actual classification of each flare.

3. The potential cost-saving benefits of implementing this rule is not considered in the estimate. These benefits may potentially include the reduced loss of products and energy, reduced utility consumption, and reduced emissions cost and liability, etc.

As shown in Table IV-4 below and Appendix V, the range of expected potential annual costs for each affected facility may range from $274,062 for a facility having only one emergency service flare, to $313,333 for a facility with five general service flares. The range of maximum potential annual costs for each facility ranges from $280,394 to $321,589.

TABLE IV-4: TOTAL ANNUAL COSTS

	Expected Potential	Maximum Potential
Operating Facilities	$2,869,222	$2,976,867
Non-Operating Facilities	$1,105,760	$1,162,749
All Facilities	$3,974,982	$4,139,616
Range per Facility		
Minimum	$274,062	$280,394
Maximum	$313,333	$321,589

CHAPTER V - COMMENTS AND RESPONSES

The following summarizes comments received and AQMD staff's response to the comments.

A. EPA Region IX Comments

No Comments

B. California Air Resources Board (CARB)

No Comments

C. Environmental Organizations

1. **Comment:** Flaring is of major concern to refinery neighbors. There is ample evidence of the overuse of flares at refineries, resulting in major emissions and noise pollution.

   Response: Flares at a refinery are part of a relief gas system and are used as an air pollution control/safety device to burn combustible gases and prevent hazardous or explosive situations. Proposed Rule 1118 is the first step in a two-step approach and will gather data on petroleum refinery operations flaring activities to determine if flares are a significant source of emissions and assess the need for, or the level of, any future controls required in order to minimize flare emissions. Presently there is not adequate data on refinery flare emissions to initiate step two of rule development

2. **Comment:** Expand the flare monitoring provisions to identify toxic feedstocks and toxic emissions.

   Response: The proposed rule will require sampling for total sulfur, hydrogen sulfide and BTU contents of the vent gases. Since toxic compounds in the flare vent gases will be subject to combustion and destruction during burning in flare, monitoring of flare vent gases does not provide accurate emission estimates and is excessively costly at this time. However, the monitored data required to be collected in the proposed rule will provide estimates on sulfur compound emissions and other criteria pollutants, some of which are considered to be toxic.

3. **Comment:** Re-evaluate methods used to estimate emissions, since they often underestimate.

   Response: The information gathered from this rule allows one to estimate emissions from flares for all criteria pollutants with much greater certainty than methods presently used. Emission factors for sulfur oxides emissions will also be significantly improved over any factors used today.

4. **Comment:** Develop requirements for actual measurement of flare gases.

Response: Direct measurement of flare vent gases is required in General Service flares and to a large extent for Emergency and Clean Service Flares. Continuous monitoring may not be required only in cases where vent gases can not be reasonably estimated using physical characteristics and operating parameters.

5. **Comment:** Move quickly on regulation to control flaring emissions, including: increased gas recovery capacity; preventing toxic emissions by removing toxic feed stocks to flares; improve flares, and, evaluating and preventing root causes of flaring episodes.

   Response: The proposed rule requires expeditious implementation of data gathering phase recognizing the uniqueness of each facility flare's design and operation. Also the data to be used for phase II should cover a period representative of full flaring operations considering turnaround times associated with various process units, before making recommendations on phase II requirements.

D. Industry

1. **Comment:** Use a "Memorandum of Understanding" approach between each refinery and the AQMD in lieu of developing a rule. This mechanism would recognize and deal effectively with the substantial differences between refineries.

   Response: AQMD staff does not agree with this comment. The proposed rule will provide a more equitable and consistent set of requirements that would apply to each facility, yet it provides adequate flexibility to consider each facility's unique flare system design and operation.

2. **Comment:** Identification of all flare events will create compliance assurance problems and should be eliminated.

   Response: The rule has been changed to identify Recordable Flare Events only.

3. **Comment:** The frequency of sampling of vent gases for total sulfur compounds and BTU content are burdensome, expensive and not necessary to estimate emissions. Periodic sampling on a weekly basis would be sufficient to give an accurate picture over time.

   Response: Sampling on a periodic basis will not result in an accurate picture of emissions especially during Recordable Flare Events. However, rule language has been added that allows a facility to propose an interim sampling and an alternative sampling program, if necessary, and will relieve a facility of potential burdensome sampling requirements.

4. **Comment:** Taking a sample during an emergency may not be possible because operators are focused on controlling the emergency.

   Response: The rule has been changed to allow sampling at alternative locations and to allow for engineering estimates for catostrophic emergencies that preclude the refinery staff from taking representative samples due to safety concerns.

5. **Comment:** Many refineries have the ability to measure specific gas flows to the flare, such as flows resulting from fuel gas knockout drum pressure control. For this instance the exact flow will be measured, and the BTU and sulfur content of the fuel are measured via existing online analyzers. No samples should be necessary.

   Response: The rule has been changed to allow a facility to use certified RECLAIM monitoring equipment, where applicable.

6. **Comment:** The District should limit the scope of the proposed rule to monitoring flares used for normal operations and exempt emergency flares.

   Response: Similar to the situation with the flares for normal operations, emissions from flares that are designated for use only during emergencies have not been well documented. Therefore, for purposes of this rule, they should also be monitored. The proposed rule will allow the operator to propose an alternative monitoring program, which once approved, may lead to less extensive requirements for monitoring emergency flares.

7. **Comment:** The District should demonstrate that there are mitigation measures that could be applied to emergency flaring even before they go into a costly data gathering effort.

   Response: The proposed rule has been revised to clearly allow an alternative monitoring program and alternative criteria for determining a recordable flare event. These alternatives will be evaluated and approved if they are capable of providing adequate emission data. These alternatives are generally easier to be developed for events involving emergency flaring, and thus, can result in significant cost reductions. Measures to mitigate emergency flaring will be developed and discussed if the results of this data gathering step of the proposed rule warrant a development of the next phase. Any discussion of mitigation measures without the underlying information is premature.

8. **Comment:** District staff has essentially created a market for ultrasonic flow measurement technology which has limited vendors and no historical information on reliability and cost of maintenance. The specification should be broadened.

Response: The proposed rule allows a variety of flow measurement technologies and the continuous flow meter specification has been revised to include a wider choices of vendors.

9. **Comment:** There are no reliable emission estimate methods available (except for SOx) for determining flare emissions. Therefore, the flare monitoring requirements specified in Attachment A (2% accuracy & 1500:1 rangeability) are not cost effective when the monitoring data is used in conjunction with less accurate emission factors.

   Response: Staff agree that the accuracy of the available emission factors is not as good as those specified above. Therefore, the proposed rule Attachment A has been revised to allow for greater flexibility.

10. **Comment:** Based on experience with the ultrasonic flow meters, more than 48 hours per quarter is needed if the meter requires calibration. The meter must be sent to the manufacturer for calibration, a process that takes about 2 weeks. While calibration is not frequently required, the rule must allow for this possibility.

    Response: The proposed rule has been revised to allow 14 days each 18 months to accommodate this manufacturer's calibration requirement.

11. **Comment:** The proposed rule states that any continuos flare monitoring system shall not be out of service due to breakdowns and system maintenance in excess of 48 hours, cumulatively, per quarter for each reporting period. Even if proper preventative maintenance is performed, breakdowns are somewhat beyond the operator's control. Therefore, we request that either the out-of-service time limit be deleted or some leeway be incorporated into the proposed Rule to ensure that a violation is not issued if the time limit is exceeded for reasons beyond the operator's control.

    Response: The downtime limitation is necessary in order to collect adequate amount of information. To provide additional flexibility and based on comments from industry the rule has been revised to allow for up to 14 days during each 18 month period for planned maintenance. For situations other than downtimes allowed in the rule and which may be beyond reasonable control, the operator may petition for a variance.

12. **Comment:** It is suggested that the District also consider the downstream impact of the data and eventual benefit, if any, to air quality and use this information to determine the cost effectiveness of the flare monitoring program. By doing so, the District will be consistent with Governor Wilson's Executive Order (W-144-97) which directs agencies to consider the cost effectiveness of regulations.

Response: The cost effectiveness analysis will be included in the emission reduction phase of the rule. Governor Wilson's Executive Order also only applies to State agencies. The requirements for cost data analysis of any proposed new or amended rule are llisted in Health and Safety Codes and AQMD is in compliance with such requirements as discussed in the Staff Report.

13. **Comment:** The applicability section should be modified such that the rule applies to main refinery flares serving one or more process units and does not apply to a small flare dedicated solely to pressurized storage tanks. A flare located in a remote area of the refinery is more difficult and costly to install instrumentation connected to our computer system for monitoring purposes.

    Response: The proposed rule has been revised so that this type of flares may be defined as "Clean Service Flares" which requires minimum amount of monitoring for determining emissions.

14. **Comment:** The proposed rule does not specify an ending date for the flare monitoring and reporting program. It is suggested that a one year monitoring and reporting period would generate sufficient data to characterize emissions from refinery flares.

    Response: Staff believes that a minimum of two years of data is required for further analysis. Therefore, a proposed resolution has been included that would direct staff to analyze the first two years of data and make a recommendation regarding any required further activities for Governing Board's consideration.

15. **Comment:** It is inappropriate to include a hydrogen production plant's flare within the scope of the Proposed Rule.

    Response: Depending on a refinery's configurations, a hydrogen production plant may or may not be independent of the other parts of operations. Where it is independent, the emissions from its flare should still be quantified but the monitoring requirements may be minimal due to the options and alternatives provided under the proposed rule.

16. **Comment:** Why is the situation "relief of excess operating pressures" included under the service category General Service Flare? Isn't it better fit under the service category Emergency Service Flare?

    Response: Some process units are designed to vent, or capable of venting, the excess gases to a flare either automatically or manually. These are included in the General Service category for emission monitoring purposes to differentiate from venting due to a pressure build up approaching the unsafe conditions during an emergency.

17. **Comment:** The definition of the term "flare event" lumps routine and non-routine (e.g., emergency, upset, unscheduled, etc.) venting of gases to the flare together. However, the majority of the flare event examples given are non-routine. This approach seems to heavily penalize any continuous venting of gas, no matter how small the volume, to the flare. In some cases, continuos venting to the flare may contain only minimal amounts of combustibles.

    Response: Continuous venting of gas with flow rates exceeding the "recordable flare event" threshold will only be required to conduct sampling once a day under the main requirements. The facility operator may, depending on the unique situation for each flare, propose an alternative program for determination of emissions.

18. **Comment:** It seems that any continuous purge would be considered as a separate flare event each day.

    Response: A continuous purge gas of the same type and quality may be included as part of the flare's purge gas with its emissions quantified accordingly. As such it will not be considered as a flare event.

19. **Comment:** Please confirm that these plans will not be subject to an annual review, for which there is a fee according to Rule 306?

    Response: Staff agrees that these plans will not be subject to fees for purposes of annual review.

20. **Comment:** The allotment of six months after approval of the Flare Monitoring and Recording Plan to start monitoring and recording may not provide sufficient time to specify, purchase, install, and commission the gas flare monitoring system. We request that the allotment be increased to nine months.

    Response: Staff believes that six months is generally adequate. However, the proposed rule has been revised to accommodate any special cases.

21. **Comment:** The monitoring and recording requirement for pilot gas flow is "Calculated, measured or manufacturer's data once per quarter." Also, for the operating parameter gas flow, the units are defined in the footnotes as scfm. Does this mean that if the pilot gas flow is measured, it is an instantaneous reading taken once each quarter, or is it a totalizer reading that is recorded once each quarter?

    Response: Monitoring requirements for pilot and purge gases have been removed from the proposed rule. The only requirement is a one time information provided with the

Flare Monitoring and Recording Plan, or any updates if there are any changes made to the purge and pilot gas quantities or qualities.

22. **Comment:** Correcting of measured flow rates for gravity/density was not addressed in the proposed Rule. Does that mean correction is not necessary?

    Response: The proposed rule requires measurement of vent gases for volumetric flow rates. Depending on the type of flow meter used, corrections for density, temperature, molecular weight, etc., may or may not be required.

APPENDIX I - FLARING ACTIVITY FROM FEBRUARY 1992, TO AUGUST 1997, BASED ON DISTRICT RECORDS

DATE	DURATION (HR)	CAUSE	CONSEQUENCES	POLLUTANT REPORTED	REPORTED AMOUNT (LB)	RULE VIOLATION	NOV
8/21/97	1.00	Unknown	Public Nuisance	None		402	Issued
8/13/97	0.33	Faulty instrument	Smoke Possible	SO_2	7,000		
8/10/97	1.00	Power Outage	Black Smoke & Odors	None		401	
8/7/97	1.00	Unknown	Public Nuisance	None		402	Issued
7/26/97	8.75	Compressor Failure	Unknown	SO_2	1,500		
7/24/97	72.00	Heat Exchanger Failure	Heavy Flaring & Noise	None			
7/11/97	0.75	Unknown	Smoke & 1 Complaint	None			
7/4/97	1.50	FCC Compressor Failure	Smoke	None		401	
7/3/97	2.00	Electrical Outage	Black Smoke, 11 Complaints	SO_2	11,947	401	
7/1/97	1.00	Source Not Found	White Smoke	None		401	Issued
5/29/97		Compressor failure & process upset	1 Complaint	None		401	
5/16/97	1.00	Unknown	Black Smoke & Nuisance	None		401& 402	Issued
5/15/97		FCC Compressor Failure	2 Complaints	None		401	
5/14/97	0.33	Unknown	Smoke	None		None	
4/30/97		Compressor Valve Breakdown	Smoke Possible	None		401	
4/9/97	1.00	Breakdown	Black Smoke & Sulfur Odors	None		401	
4/3/97	2.00	Pump Fire	Smoke	None		401	
2/22/97	0.50	Fire	Smoke Possible	SO_2	16,700		
2/15/97	0.17	Process upset	Smoke	None		401	
1/13/97	3.00	Fire at Process Unit	Black smoke	None		401	
1/9/97	3.00	Explosion	Black Smoke	SO_2	40,700	401	
1/8/97		Breakdown	Black Smoke	None		401& Var.	
1/7/97	0.50	Breakdown	Black Smoke	SO_2	4,240	203 & 401	
1/3/97	0.50	Power Dip	Black Smoke	None		401	
12/22/96	1.00	Electrical Outage	Black Smoke	None		203 & 401	
12/18/96	1.00	Operator Error	Black Smoke & 2 Complaints	None		401	Issued
12/5/96	9.00	Compressor Failure & Breakdown	Unknown	None		401 & 203	
12/3/96	1.00	Unknown	Public Nuisance	None		402	Issued

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DATE	DURATION (HR)	CAUSE	CONSEQUENCES	POLLUTANT REPORTED	REPORTED AMOUNT (LB)	RULE VIOLATION	NOV
11/24/96		Power Failure	Unknown	None			
11/21/96	1.00	Process Unit Fire	Black Smoke & Odor Nuisance	None		401 & 402	Issued
11/8/96	0.50	Hydrocracker Compressor	Smoke & 1 Complaint	None		401	
11/6/96	0.25	Failed Instrument	Black Smoke	None		401	
10/22/96	264.00	Compressor Failure	Numerous Complaints, 22 Sent to Hospital	None		402	
10/7/96	24.00	Process upset	1 Complaint	None		401	
9/29/96	1.33	Compressor Failure	Unknown	SO_2	1,188		
9/24/96	0.25	Compressor Failure	Unknown	None			
9/18/96		Process upset	1 Complaint	None		401	
9/6/96	336.00	Process upset	Public Nuisance	None		402	Issued
9/5/96	0.50	Error	Black Smoke	None		203 & 401	
8/14/96	10.00	Leaking PRV	Brown Smoke	None			
8/10/96	1.00	West Coast Power Dip	Heavy Flaring & Black Smoke	None		401	
8/10/96	1.00	Power Dip	Smoke	None		401	
7/30/96	0.25	Error	Black Smoke & 2 Complaints	None		203 & 401	
7/10/96		Breakdown	Unknown	None			
7/6/96		Breakdown	Unknown	None			
7/2/96	0.17	Power Outage	Unknown	SO_2	6,200		
7/1/96		Process upset	Unknown	None			
6/28/96		Process upset	Unknown	None			
6/26/96	3.00	Start-up & Unknown	Smoke & 2 Complaints	None		401	
6/25/96		VR Compressor Failure	Unknown	None			
6/25/96	15.00	Power Failure	Smoke Possible	SO_2	6,200		
6/18/96	1.00	Pilots Out	Public Nuisance	None		402	Issued
5/18/96		Compressor Breakdown	Unknown	None			
5/15/96	0.50	Process upset	Smoke, Odors & 2 Complaints	None		401	
4/16/96		Power Failure	Unknown	None			
4/12/96		Power Dip	Unknown	None			
4/7/96		VR Compressor Failure	Unknown	None			
3/22/96		Breakdown	Unknown	None			
3/7/96		Unknown	Smoke	None		401	Issued
2/27/96		Power Failure	Unknown	None			

APPENDIX I - FLARING ACTIVITY FROM FEBRUARY 1992, TO AUGUST 1997, BASED ON DISTRICT RECORDS

DATE	DURATION (HR)	CAUSE	CONSEQUENCES	POLLUTANT REPORTED	REPORTED AMOUNT (LB)	RULE VIOLATION	NOV
2/14/96		Process Upset	Unknown	None			
2/13/96		Process upset	Possible Flaring	None			
2/4/96		Power Failure	Unknown	None			
1/13/96		Fire	Possible Flaring	None			
1/3/96		Unknown	4 MMscfh, 9000 ppm	H_2S		401	
12/17/95		Coker Heater	Possible Flaring	None			
12/10/95		Crude Tower Upset	Unknown	None			
11/28/95		Isomax	Unknown	None			
11/24/95		Power Failure	Unknown	None			
11/10/95		Coker Compressor Failure	Unknown	None			
10/27/95		FCCU	Unknown	None			
10/16/95		GTG Fire	Possible Flaring	None			
10/2/95		Power Dip	Unknown	None			
9/25/95		Isomax	Unknown	None			
9/5/95		Fire	Unknown	None		401	
9/5/95		Power Dip	Unknown	None			
8/30/95		CO Boiler	Possible Flaring	None			
8/28/95		Isomax	Unknown	None			
8/24/95		Isomax	Unknown	None			
8/24/95		Wet Gas Compressor Breakdown	Unknown	None			
8/17/95		Isomax	Unknown	None			
8/8/95		Flare Malfunction	Unknown	None			
7/30/95		Power Outage	Unknown	None			
7/26/95		Coker	Unknown	None			
7/12/95		VR Compressor Failure	Unknown	None			
7/1/95		Unit SO.	Unknown	None			
6/23/95		Power Failure & Explosion	Unknown	None			
6/2/95		Power Dip	Unknown	None			
4/13/95		VR Compressor Failure	Smoke	None		401	Issued
4/12/95		Power Outage	Unknown	None			
3/24/95		Power Outage	Unknown	None			
3/24/95		VR Compressor Valve Failure	Unknown	None			
3/13/95		Crude Unit Relief	Unknown	None			
3/4/95	2.00	Breakdown	Unknown	SO_2	22,955		
2/16/95		FCC Wet Gas Compressor Failure	Unknown	None			
2/13/95		VR Compressor Failure	Unknown	None			
2/3/95		SRU Power Failure	Unknown	None			
1/12/95		Unknown	65,000 ppm	H_2S			

APPENDIX I - FLARING ACTIVITY FROM FEBRUARY 1992, TO AUGUST 1997, BASED ON DISTRICT RECORDS

DATE	DURATION (HR)	CAUSE	CONSEQUENCES	POLLUTANT REPORTED	REPORTED AMOUNT (LB)	RULE VIOLATION	NOV
12/2/94	170.00	Wet Gas Compressor Damage	Unknown	Hydrocarbons	2,670		
11/15/94		Unknown	5 MMscfh, 3000ppm	H_2S		401	Issued
11/9/94	18.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	501		
10/14/94	1.25	Wet Gas Compressor Failure	Unknown	H_2S	61	401	Issued
10/11/94	32.00	Wet Gas Compressor Discharge Plug	Unknown	Hydrocarbons	766		
9/28/94		Pilots Out	0.05 MMscfh	None		401	Issued
8/16/94	5.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	129		
7/26/94		Instrument Air Failure	Unknown	SO_2	6,818		
7/1/94	10.00	Wet Gas Compressor Discharge Plug	Unknown	Hydrocarbons	216		
1/2/94	0.75	SRU Breakdown	Unknown	SO_2	10,365		
10/22/93	1.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	1		
10/19/93		Wet Gas Compressor Breakdown	Unknown	SO_2	740		
10/7/93	2.50		Unknown	SO_2	0		
10/6/93	6.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	1		
10/6/93	3.00	Power Outage	Unknown	SO_2	1,180		
9/14/93	26.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	210		
8/8/93	63.00	Wet Gas Compressor Discharge Plug	Unknown	Hydrocarbons	2,000		
7/29/93	41.00	Wet Gas Compressor Discharge Plug	Unknown	Hydrocarbons	1,302		
7/18/93	1.62	Exchanger Breakdown	Unknown	Hydrocarbons	482		
7/12/93	101.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	3,222		

APPENDIX I - FLARING ACTIVITY FROM FEBRUARY 1992, TO AUGUST 1997, BASED ON DISTRICT RECORDS

DATE	DURATION (HR)	CAUSE	CONSEQUENCES	POLLUTANT REPORTED	REPORTED AMOUNT (LB)	RULE VIOLATION	NOV
7/7/93	0.63	Exchanger Breakdown	Unknown	Hydrocarbons	775		
7/3/93	15.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	714		
6/9/93	19.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	786		
6/2/93	12.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	238		
4/11/93	2.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	32		
3/29/93	1.00	Wet Gas Compressor Breakdown	Unknown	SO_2	2,950		
3/11/93	18.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	786		
2/28/93		Over Pressure	Unknown	Hydrocarbons	113		
1/26/93	54.00	Wet Gas Compressor Discharge Plug	Unknown	Hydrocarbons	1,714		
1/19/93	4.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	149		
1/14/93	37.00	Wet Gas Compressor Breakdown	Unknown	SO_2	740		
12/28/92	6.00	Hole In Line	Unknown	SO_2	2,700		
12/4/92	0.23	SRU Shutdown	Unknown	SO_2	3,200		
11/24/92	12.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	373		
11/20/92	5.00	Wet Gas Compressor Breakdown	Unknown	SO_2	434		
11/17/92	80.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	2,222		

APPENDIX I - FLARING ACTIVITY FROM FEBRUARY 1992, TO AUGUST 1997, BASED ON DISTRICT RECORDS

DATE	DURATION (HR)	CAUSE	CONSEQUENCES	POLLUTANT REPORTED	REPORTED AMOUNT (LB)	RULE VIOLATION	NOV
11/10/92	34.00	Wet Gas Compressor Discharge Plug	Unknown	Hydrocarbons	2,175		
10/28/92	0.50	Pump Failure	Unknown	SO_2	397		
9/28/92	1.00	Power Failure	Unknown	SO_2	4,233		
8/28/92	1.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	67		
8/14/92	0.83	Level Control Failure	Unknown	H_2S	8,800		
8/4/92	8.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	444		
7/19/92	7.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	357		
7/11/92	2.00	Wet Gas Compressor Breakdown	Unknown	SO_2	39,800		
7/7/92	69.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	6,068		
6/12/92		Level Control Failure	Unknown	SO_2	11,220		
5/24/92	16.00	Wet Gas Compressor Maintenance	Unknown	Hydrocarbons	750		
3/31/92	104.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	5,789		
3/21/92	82.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	2,297		
2/17/92	1.00	Wet Gas Compressor Breakdown	Unknown	SO_2	14		
2/14/92	118.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	3,372		
2/6/92	38.00	Wet Gas Compressor Breakdown	Unknown	Hydrocarbons	3,016		

APPENDIX II - SUMMARY OF NOVEMBER 1995, INFORMATION GATHERING SURVEY

On November 30, 1995 an information survey was sent to 21 potentially affected facilities. Six facilities responded to the survey. The following is a brief summary of some of the responses:

1. Provide a process flow diagram of the flare and vapor recovery system which identifies the following:

    - Flare type and design capacity

Refinery 1	5 elevated flares with a total capacity of 19,943 MSCFH.
Refinery 2	5 elevated and 1 ground flare with a total capacity of 5,698,700 LB/hr.
Refinery 3	2 elevated flares and 2 ground flares with a total capacity of 4,266,000 LB/hr.
Refinery 4	One flare rated at 350,000 LB/hr.
Refinery 5	2 elevated flares and didn't specify ratings.
Refinery 6	4 elevated flares with a total capacity of 819,000 LB/hr, LPG flare rating not provided.

    - Pilot and purge gas

	Pilot	Purge
Refinery 1	Not Provided	Not Provided
Refinery 2	Natural	Natural and Refinery
Refinery 3	Natural, Refinery & Propane	Natural, Refinery & Propane
Refinery 4	Natural, Refinery	Natural, Refinery
Refinery 5	Not Provided	Not Provided
Refinery 6	Refinery	Refinery

    - Design capacity of compressor and vapor recovery system

Refinery 1	Not provided.
Refinery 2	4 separate systems with a total capacity of 10.4 MMSCFD.
Refinery 3	One system with a total capacity of 1.347 MMSCFD.
Refinery 4	One system with a total capacity of 20 MMSCFD.
Refinery 5	Not provided.
Refinery 6	One system with a total capacity of 5.592 MMSCFD.

2. Describe the current flow metering and recording methods for pilot gas, purge gas and flare gas. Include type of flow meter, accuracy of flow meter, maintenance costs, maintenance schedules and any known problems with current flow metering and recording methods.

- Pilot Gas

Refinery 1	Not metered.
Refinery 2	Some systems are not metered while others have local orifice type (Didn't identify).
Refinery 3	Orifice plates.
Refinery 4	Orifice plates with differential pressure cells, ± 5% minimal maintenance.
Refinery 5	Not provided.
Refinery 6	Not metered.

- Purge Gas

Refinery 1	Not metered.
Refinery 2	Natural and Fuel Gas - Natural Gas. Some systems are not metered while others have local orifice type (Didn't identify).
Refinery 3	Not provided.
Refinery 4	Orifice plates with differential pressure cells, ± 5% minimal maintenance.
Refinery 5	Not provided.
Refinery 6	Not metered.

- Flare Gas

Refinery 1	Potential sample ports located throughout flare system and flow meters are currently not in use.
Refinery 2	Each Flare has a thermal dispersion mass flow meters. Some systems include a gravity/density meter for correcting measured flow. Probe element failure and inability to maintain calibration have been the major reliability problem. Probe calibration conducted in vendors shop which is costly and time consuming. None are currently on-line.
Refinery 3	Flare system is sequentially operated. Initial ground flare is monitored with an ultrasonic meter. Maintenance costs are not available but believed to be high and reliability is poor even with extensive maintenance. Accuracy is unknown.
Refinery 4	Thermal Dispersion Mass Meter. Moderate. ± 33% accuracy due to varying density of gases with high daily maintenance costs.
Refinery 5	Thermal flow meters are used to measure flows to the flares and from the process units. Inaccurate due to varying mass.
Refinery 6	Various meters (not identified) and readings are archived.

3. Describe the current monitoring and recordkeeping methods for flaring events and quality of gases for sulfur content, BTU content, VOCs and toxics.

Refinery 1	Visual monitoring of flare operation with no recordkeeping.
Refinery 2	Currently monitoring flare header pressure with no sampling.
Refinery 3	Initial ground flare meter output is recorded electronically. Analyzed for H_2S on a periodic basis.
Refinery 4	Monitored flow and H_2S content.
Refinery 5	A sample of flared gas is taken once a week and analyzed for hydrocarbon composition, specific gravity, BTU content and H_2S. Electronically record flow rates of flared gases.
Refinery 6	Monitor process control valve position for those control valves that regularly release to vapor recovery or relief header. Fuel gas relief header is monitored by a CEMS for H_2S.

4. Describe any past attempts to monitor and record the quantity and quality of gases vented to the flare system and why they were abandoned.

Refinery 1	Monitored for one year in 1988 under CARB Resolution 86-80 and abandoned due to high maintenance.
Refinery 2	Gravity/density meters abandoned due to reliability problems, inaccurate and high maintenance costs.
Refinery 3	Attempted to monitor flow rates to individual but abandoned due to reliability and maintenance costs as well as the inability of meters to measure highly variable flows.
Refinery 4	Quit using density meter due to reliability.
Refinery 5	None other than grab samples for various reasons.
Refinery 6	None.

5. Describe any methods that could be used to estimate the quantity and quality of gases being flared that are relatively accurate and reliable.

Refinery 1	Thermal dispersion, sonic (Doppler or transit time) and Delta P (annubar with nitrogen blowback and correction factor).
Refinery 2	None.
Refinery 3	Unaware of any methods. However, due to the sequential operation of the flare system, the initial flare is monitored which covers most flaring events. This limits the high costs of maintenance.
Refinery 4	Unaware of any methods.
Refinery 5	Continuous GC analysis.
Refinery 6	To broad of a question to reasonably respond to in this venue.

6. If available, provide analysis (sulfur content, BTU content, etc.) of gases vented to the flare and records of flow meter readings for calendar years 1993 and 1994.

Refinery 1	None available.

Refinery 2 None provided.
Refinery 3 Three years of flow data was provided with an average of 1.7 MMSCFD which was reduced to 0.4 MMSCFD with a new vapor recovery system. Average H_2S concentration was 1670 ppm and ranged from trace to 13000 ppm based on draeger tube readings.
Refinery 4 Provided extensive data.
Refinery 5 Provided data for 1995.
Refinery 6 Have H_2S content records for fuel gas vented to a flare which are quite voluminous. Will provide if determined necessary. Also provided flow data for some lines venting to flare.

7. Describe any "routine" flaring of gases conducted by the refinery that is not related to process upsets, turnarounds or other safety reasons.

Refinery 1 No routine flaring conducted.
Refinery 2 Excessive pressures in the vapor recovery systems are vented to the flare.
Refinery 3 Intermittent venting from excessive pressures in the vapor recovery system, sight glasses, compressor bottles, sampling systems, and pump and compressor case vents.
Refinery 4 Excessive pressures in the vapor recovery.
Refinery 5 No routine flaring conducted.
Refinery 6 Fuel gas header, hydrogen heater and crude/coker unit pressure balances, "sweep" fuel gas for good flare operation and intermittent relief's such as sample station and level indicator blowdown.

8. Describe any controls or flaring minimization plans currently in place or planned in the near future.

Refinery 1 None.
Refinery 2 None. Vapor recovery System is sized to accommodate the normally expected process vents and recover these gases to the refinery fuel system.
Refinery 3 Upgraded the vapor recovery system in mid 1994 by replacing compressors and increasing capacity. Resulted in the decrease of flow rates to the initial flare from 1.7 MMSCFD to 0.4 MMSCFD. They also sell gas to a local utility.
Refinery 4 Provided extensive information.
Refinery 5 Vapor recovery system.
Refinery 6 Operating the vapor recovery compressor to the fullest extent possible.

9. Describe any improvements or upgrades that have been implemented at the refinery over the last couple of years that have resulted in the reduction of flaring activities.

Refinery 1 None.
Refinery 2 None.
Refinery 3 See No. 8.

Refinery 4	Reduction in flared gases as a result of Flare Study.
Refinery 5	In order to manufacture RFG, they installed autolockouts and autostarts at the Alkylation unit which would reduce potential flare load by allowing a tower to maintain steady state during refinery emergencies. Also replace valves that leak to the flare system during down times.
Refinery 6	Installation of new vapor recovery compressor in 1992.

APPENDIX III - SUMMARY OF AUGUST 1997, INFORMATION GATHERING SURVEY

A letter was sent to affected operating refineries, requesting them to categorize there gas flares as general safety, clean service or emergency service flares. Table AIII-1 is a summary based on their responses. Table AIII-2 categorizes the flares at non-operating refineries, which is based on the initial November 30, 1995 survey letter.

Table AIII-1: Operating Facilities

Company	General	Clean	Emergency	Total	Comments
1	1	0	0	1	
2	5	0	0	5	
3	0	0	6	6	Didn’t Respond. Based on initial survey
4	0	0	4	4	Sequential Operation, with existing Flow Meter
5	1	0	0	1	
6	2	0	0	2	Existing Flow Meter
7	1	0	0	1	Existing Flow Meter
8	2	0	0	2	
9	5	0	0	5	
10	0	1	3	4	
Total	17	1	13	31	

Table AIII-2: Non-Operating Facilities

Company	Safety	Clean	Emergency	Total	Comments
1	0	0	2	2	
2	0	0	4	4	
3	0	0	1	1	Existing Flow Meter
4	0	0	2	2	
Total	0	0	9	9	

Table AIV-1 is a summary of a telephone survey of facilities that have installed ultrasonic flow meters on elevated gas flares. Three refineries, one petrochemical plant, one ethylene plant, one gas plant and one oil and gas production facility were surveyed for a total of seven facilities. There were a total of 48 meters installed with a range of one to ten years of operating experience. The installed cost per meter ranged from $22,000 to $50,000 with an average cost of $40,000. Typical reasons why ultrasonic meters were installed were: to obtain information on flaring activities; to reduce flaring activities which resulted in saving product and money; anticipation of upcoming rules and regulation; and, required by local Air Pollution Control agency for an oil and gas production facility.

Table AIV-1

Facility	# Meters	# Years	Installed Cost ($1,000)	Why Installed	How Installed	Flare Type	Gas Type	Flare Capacity
Refinery	10	10	220	Info.	Hot Tap	Elev.	Ref.[1]	2x 10^5 lb/hr
Refinery	27	3	1,350	Info. & Reduce	Hot Tap	Elev.	Ref.[1]	0-100 ft/s
Petro/Chem	1	3	40-50	Info/Report	Hot Tap	Elev.	65% Methane	Unknown
Ethyl. Plant	2	3	90	Info/Econ	Cold Tap	Elev.	C_5-C_6	Unknown
Refinery	3	4	105	Info	Cold Tap	Elev.	Ref.[1]	10^6 lb/hr
Gas Plant	4	7	150	Info/Econ	Hot Tap	Elev.	C_5-C_6	10^5 lb/hr
Oil & Gas	1	1	Unknown	Required	Hot Tap	Elev.	Methane & H_2S	Unknown

1 Typical Refinery Gas consisting of hydrocarbons up to C_6-C_7 with high H_2S.

A. INITIAL COST

Capital Cost of Installing Flare Monitoring System

Cost Item	Cost for General Service Flare	Cost for Emergency or Clean Service Flare
Flow		
Meter	$20,000	N/A
On/Off Indicator	N/A	$400
Installation		
Transducer (Hot Tap)	$7,000	N/A
On/Off Indicator	N/A	$2,000
Electrical/Data Conduit and Cables	$20,000	$5,000
Integrate with RECLAIM Computer or Strip Chart	$1,000	$1,000
Power Supply	$1,500	$1,500
Planning and Supervision	$2,000	$2,000
Sub Total	$51,500	$11,900
Contingency (30%)	$15,450	$3,570
Grand Total	**$66,950**	**$15,470**

Flare Monitoring and Recording Plan Cost

Cost Item	Cost for Each Facility
Monitoring Plan Preparation 200 hr @ $50/hr	$10,000
Plan Fees	
Filing Fee	$341
T&M 40 hr @ $78.60/hr	$3,144
Total	**$13,485**

B. ANNUAL OPERATION AND MAINTENANCE PER FACILITY

Cost Item	Cost	Quantity	Total Cost
Maintenance	Negligible	N/A	$0
HHV Analysis	$200	500	$100,000
Sulfur Analysis	$300	500	$150,000
Sampling Equipment	$10	500	$5,000
Sampling Labor	$27/hr	500	$13,500
Quarterly Report Preparation	$50/hr	40	$2,000
Total			**$270,500**

C. EXPECTED POTENTIAL ANNUAL INDUSTRY COSTS FOR OPERATING FACILITIES

Amortized Capital Cost

Cost Item	Cost per Item	Quantity	Total Cost	Amortized1
Emergency Service Flare	$15,470	16	$247,520	$30,445
Clean Service Flare	$15,470	1	$15,470	$1,903
General Service Flare	$66,950	14	$937,300	$115,288
Plan Preparation & Fees	$13,485	10	$134,850	$16,586
Total				**$164,222**

1. Amortized over 10 years @ 4% real interest rate

Annual Operation and Maintenance Cost

Cost Item	Cost per Item	Quantity	Total Cost
Operation and Maintenance	$270,500	10	$2,705,000

Expected Potential Annual Cost

$164,222 + $2,705,000 = $2,869,222

D. EXPECTED POTENTIAL ANNUAL INDUSTRY COSTS FOR NON-OPERATING FACILITIES START OPERATIONS

Amortized Capital Cost

Cost Item	Cost per Item	Quantity	Total Cost	Amortized1
Emergency Service Flare	$15,470	9	$139,230	$17,125
Clean Service Flare	$15,470	0	$0	$0
General Service Flare	$66,950	0	$0	$0
Plan Preparation & Fees	$13,485	4	$53,940	$6,635
Total				**$23,760**

1. Amortized over 10 years @ 4% real interest rate

Annual Operation and Maintenance Cost

Cost Item	Cost per Item	Quantity	Total Cost
Operation and Maintenance	$270,500	4	$1,082,000

Expected Potential Annual Cost

$23,760 + $1,082,000 = $1,105,760

E. TOTAL EXPECTED POTENTIAL ANNUAL INDUSTRY COSTS

$2,869,222 + $1,105,760= $3,974,982

F. RANGE OF ANNUAL COSTS PER FACILITY

Minimum (One Emergency Service Flare)	$274,062
Maximum (Five General Service Flares)	$313,333

G. OVERALL MAXIMUM POTENTIAL COST

This estimate is based on the following assumptions:

1. All the 10 operating facilities and four currently non-operating will implement the rule upon rule adoption.
2. All facilities will install a flare monitoring system that meets the requirements for a general service flare regardless of the actual classification of each flare.
3. The potential cost-saving benefits of implementing this rule is not considered in the estimate. These benefits may potentially include the reduced loss of products and energy, reduced utility consumption, and reduced emissions cost and liability, etc.

Amortized Capital Cost

Cost Item	Cost per Item	Quantity	Total Cost	Amortized1
General Service Flare	$66,950	40	$2,678,000	$329,394
Plan Preparation & Fees	$13,485	14	$188,790	$23,221
Total				**$352,615**

1. Amortized over 10 years @ 4% real interest rate

Annual Operation and Maintenance Cost

Cost Item	Cost per Item	Quantity	Total Cost
Operation and Maintenance	$270,500	14	$3,787,000

Overall Maximum Potential Annual Cost

$352,615 + $3,787,000 = $4,139,615

H. RANGE OF OVERALL MAXIMUM POTENTIAL COST

Minimum (One General Service Flare)	$280,394
Maximum (Six General Service Flares)	$321,568

Table AVI-1 is a partial list, provided by a manufacturer of ultrasonic flow meters, of installed ultrasonic flow meters at refineries, oil and gas production and petrochemical facilities.

Table AVI-1

Company Name	Location	# of Units
AMOCO OIL	US	1
AMOCO OIL	US	40
AMOCO OIL	US	7
ARCO CHEMICAL	US	1
ASHLAND PETROLEUM	US	8
BARIVEN	Venezuela	1
BASF	US	2
BP OIL	US	3
BROWN & ROOT	Saudi Arabia	3
CAL RESOURCES	US	2
CHINESE PETROLEUM	China	1
CYTEC IND.	US	1
EXXON CORP.	US	27
LUBRIGOL CORP.	US	1
LYONDELL-CITGO	US	3
MW KELLOGG	Saudi Arabia	1
PETROBRAS AMERICA	Brazil	1
SHELL OIL	US	1
SHELL REFINERY	US	10
SHELL UK	UK	2
STAR ENTERPRISE	US	3
TEXACO	US	4
UNOCAL	US	1

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