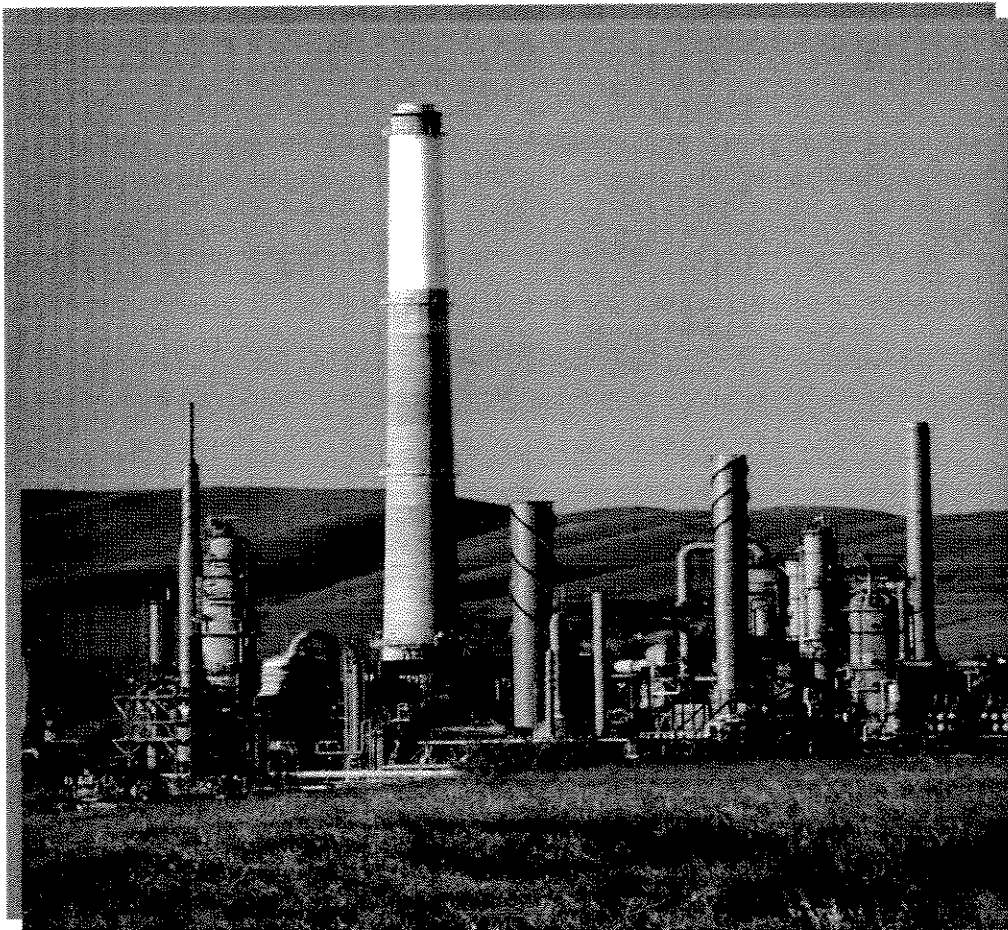


*Regulation 12-12  
Flare Minimization Plan  
Benicia Refinery*



PUBLIC VERSION

Revision No. 3.2

July 16, 2008 (Revised September 16, 2008 and April 17, 2009)



## **Benicia Refinery**

### **Bay Area Air Quality Management District Regulation 12-12**

### **Flare Minimization Plan**

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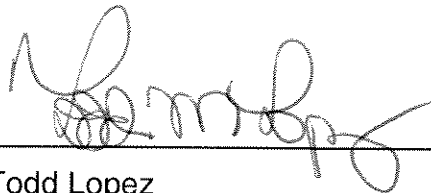
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### CERTIFICATION

*I, Todd Lopez, certify that based on the information available to me, the information provided herein is accurate, true and complete.*



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Todd Lopez  
Environmental Manager  
Valero Benicia Refinery  
VALERO REFINING COMPANY – CALIFORNIA



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Date

## EXECUTIVE SUMMARY

On July, 20, 2005, the Bay Area Air Quality Management District's (BAAQMD) Board of Directors adopted Regulation 12-12. The BAAQMD's stated objectives for the rule were and are to minimize the frequency and magnitude of flaring events at petroleum refineries, and therefore reduce emissions (Regulation 12-12-101). However, despite these objectives, the BAAQMD made clear that nothing in the rule should be construed to compromise refinery operations and practices with regard to safety (Ibid.).

It is worth stressing that with regard to safety the BAAQMD recognized that because flares are first and foremost safety devices that must be available at all times for use in various situations to prevent accident, hazard, or release of refinery gas directly to the atmosphere, the formulation of a rule that will minimize the frequency and magnitude of flaring events at petroleum refineries, and therefore reduce emissions, must provide refineries with flexibility to address their unique flare systems without compromising the safety of workers and the public or the refineries.

To achieve the BAAQMD's objectives of minimizing the frequency and magnitude of flaring events, the rule prohibits flaring except for emergencies and as necessary to prevent an accident, hazard, or release of vent gas directly to the atmosphere, unless it is consistent with an approved Flare Minimization Plan (FMP) and all commitments due under that plan have been met (Regulation 12-12-301).

The rule requires that by August 1, 2006, the owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit a FMP as required by Regulation 12-12-401 (Regulation 12-12-402). Regulation 12-12-401 indicates that the elements of an FMP<sup>1</sup> include:

1. A description of and technical information for the refinery flare system and the upstream equipment and processes that send gas to the flare, including all associated monitoring and control equipment;
2. A description of the equipment processes and procedures previously installed or implemented by the owner or operator within the last five years to reduce the flaring;
3. A description of any equipment, process or procedure to reduce flaring that is planned, but not yet installed or implemented and the schedule for completion; and
4. A description and evaluation of prevention measures, including a schedule for the implementation of all feasible prevention measures to address the following:
  - flaring during planned major maintenance activities including startup, shutdown, and turnaround;
  - flaring that may occur due to issues of fuel gas quantity or quality; and

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<sup>1</sup> The BAAQMD has emphasized that an FMP is not intended to serve as a permit for a flare or to be included as part of the refinery permit, and therefore, the plan is not subject to provisions of the Health and Safety Code or BAAQMD rules related to permits.

- flaring caused by the recurrent breakdown of equipment.
5. Any other information requested by the Air Pollution Control Officer as necessary to enable determination of compliance with applicable provisions of this rule.

The following FMP for the Valero Refining Company – California; Benicia Refinery (Benicia Refinery) has been prepared with the BAAQMD's objectives in mind: to minimize the frequency and magnitude of flaring events at the refinery without compromising refinery operations and practices with regard to safety, and to comply with the Regulation 12-12-401 FMP requirements. Additionally, to comply with Regulation 12-12-301, which as noted above prohibits non-emergency and non-safety-related flaring unless it is consistent with an approved FMP, the following FMP covers flaring associated with the following broad categories of events:

- maintenance activities including process unit startup, shutdown, and turnaround events;
- fuel gas quantity and quality issues such as a fuel gas imbalance or out of range fuel gas heating value (Btu);
- equipment failure and malfunction including process upsets; and
- emergency<sup>2</sup> conditions beyond the reasonable control of the Benicia Refinery or its operators caused by sudden, infrequent and not reasonably preventable equipment failure, natural disaster, acts of war or terrorism, external power curtailment, loss of utilities (e.g., power, cooling, steam, and instrument air), or fire; and
- safety – to prevent an accident, hazard, or release of vent gas directly to the atmosphere<sup>3</sup>.

The original FMP specifically provided the background information required by the regulation regarding the Benicia Refinery, the Flare Gas Recovery System, and the associated flares. Specifically, the FMP includes a discussion of measures that the Benicia Refinery has implemented to minimize flaring, a review of recent historical rates of flare gas recovery and flaring events (1995 to 2006), a discussion of flaring that may continue to occur for safety and environmental reasons, and a review of the refinery's ongoing flare minimization procedures. It is worth noting and emphasizing that over the past 30 years the Benicia Refinery has made continuous improvement with respect to flare minimization with dramatic improvement in recent years.

Additionally, Regulation 12-12-404.1 requires that no more than 12 months following approval of the original FMP and annually thereafter, the owner or operator of a flare subject to this rule shall review the FMP and revise the plan to incorporate any new prevention measures identified as a result of the analyses prescribed in Sections 12-12-401.4 and 12-12-406. The updates must be approved and signed by a Responsible Manager. This document is the annual update designed to meet the requirements of

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<sup>2</sup> Not subject to the Regulation 12-12-301 standard, but listed since the FMP addresses these types of flaring events.

<sup>3</sup> Not subject to the Regulation 12-12-301 standard, but listed since the FMP addresses these types of flaring events.



Regulation 12-12-404.1 and to that end, the changes to the FMP are primarily in Sections 3 and 4.

At the Benicia Refinery, flare minimization procedures have been implemented through a combination of procedural approaches and equipment upgrades targeted at minimizing the flow of gases to the refinery's Flare Gas Header, and maximizing the recovery of gases from that system for reuse. Key aspects of this approach include the development of an effective maintenance program to reduce unplanned flaring, monitoring of flows in the Flare Gas Header, a program to identify the sources of base loads if they start to rise, and operational planning to minimize or eliminate flaring during planned or anticipated maintenance events. A final important component is the refinery's program to evaluate the cause of significant flaring events that do occur, with the lessons learned from the causal analysis incorporated as appropriate into refinery operations, planning, and/or maintenance procedures. Based on historical data, significant events account for over 90 percent of the flaring volume and emissions. Accordingly, the causal analysis reports and the flare minimization efforts are appropriately focused on the activities where there is the greatest potential for reductions.

Using this causal analysis approach during the last 5 to 10 years has allowed the refinery to significantly minimize the frequency and magnitude of flaring events. During this period, flaring has been reduced by more than 50 percent refinery-wide. Based on a review of available industry data and the 2005 flaring inventories for Bay Area refineries posted on the BAAQMD web site, the five Bay Area refineries use their flares significantly less than a typical refinery located elsewhere in the United States and represent some of the industry's best practices. These data also shows that in 2005 the Benicia Refinery flared about 50 percent less than the average Bay Area refinery on a volumetric basis, and performed better than average for all measures of emissions even after adjusting for differences in refinery sizes. This FMP and subsequent updates will become an integral component of the Benicia Refinery's continuing program to sustain and improve upon the exceptional results already achieved.

Accordingly, this FMP for the Benicia Refinery meets Regulation 12-12 requirements and will serve as an important component of the Benicia Refinery's continued efforts to minimize the frequency and magnitude flaring. Pursuant to Regulation 12-12-403, the Benicia Refinery requests timely approval of the following FMP by the BAAQMD.

Appendices B and C of this FMP contain refinery confidential information and are trade secrets and confidential business information (CBI) of Valero Refining Company – California (Valero) as defined by the California Public Records Act, Government Code Section 6254.7 et seq., and the Freedom of Information Act, 40 CFR Part 2 (40 CFR §2.105(a)(4)), 5 USC 552(b)(4), and 18 USC 1905. Because of the sensitive and competitive nature of the information, Valero requests that the BAAQMD afford the information CBI status and treatment indefinitely. The content of Appendices B and C in the public version of this FMP have been redacted. A complete copy of the FMP, including Appendices B and C, is included in the CBI version of the FMP provided to the BAAQMD.

## **SECTION 1 OVERVIEW OF REFINERY OPERATIONS AND FLARE MINIMIZATION**

This section of the FMP provides a general overview of refinery operations, flare gas recovery, and flare systems for a typical refinery. This section also provides more specific information regarding the Benicia Refinery's Flare Gas Recovery System, flaring frequency and magnitude, and flare minimization procedures. It is hopeful that this information will provide an introductory background to assist the reader in reviewing the more detailed technical information provided in Sections 2 through 5, which directly comply with the specific Regulation 12-12-401 requirements.

### **1.1 General Refinery and Flare System Background Information**

The processing of crude oil within a refinery is a complex operation that starts with the receipt of materials by ship or by pipeline and includes a variety of processing operations which ultimately produce a broad range of marketable fuel products. Within the extensive processing operations, equipment operates at a variety of pressures and temperatures and must safely manage materials that are flammable or harmful if released to the environment in an uncontrolled manner. Refinery flare gas recovery systems and their associated flares play a key role in this process. As noted by the BAAQMD, refinery flares are necessary for the safe disposal of gases generated during the refining process.

#### **1.1.1 Refining/Refinery Overview**

Refineries process crude oil by separating it into a range of hydrocarbon components or fractions, and then rearranging those components to produce products which satisfy a market demand. Petroleum fractions include heavy oils and residual materials used to make asphalt or petroleum coke, mid range materials such as diesel (heating oil), jet fuel and gasoline, and lighter products such as butane, propane, and fuel gases.

Oil refineries are organized into groups of process units, with the general goal of maximizing the production of gasoline and diesel fuels. Each unit takes in a set of feed streams and produces a set of product streams with the composition changed (or upgraded) as one step toward production of an optimal mix of refined products. These separation and rearrangement processes also produce and/or consume materials that are gases at atmospheric pressure. As a final step in processing, many units provide treatment to conform to regulatory specifications such as reduced sulfur levels. Many of these processes operate at elevated temperatures and pressures, and a critical element of safe design is having their capability of releasing excess pressure via relieving devices to the flare gas header to manage excess materials in a controlled manner.

#### **1.1.2 Refinery Fuel Gas Production**

Refineries are designed and operated so that there will be a balance between the rates of fuel gas production and consumption. Under normal operations most gases produced by the refinery are routed directly to the refinery's fuel gas unit, allowing them to be used as a source of fuel in refinery furnaces, boilers, and

other combustion devices. Typical refinery fuel gas units operate with a base loading of fuel gases generated in the refinery with additional natural gas supplied to the system as needed on pressure control to satisfy the refinery's total energy requirement. This provides a simple way to keep the system in balance, so long as the demand for fuel gas exceeds the amount of fuel gas produced (i.e., the so-called "fuel gas balance"). Some additional operational flexibility is typically maintained by having the ability to burn other fuels such as propane or butane, and to a limited extent having the capability to adjust the rate of fuel gas consumption at furnaces, boilers, and other combustion devices.

Flared gases can potentially be recovered for blending into the fuel gas unit if they are of proper quality for reuse - of light hydrocarbon content with sufficient fuel value, not primarily nitrogen or steam or other low Btu gases, and not excessively high in sulfur content. Reuse also depends on having sufficient treatment and consumption capacity available.

### **1.1.3 Refinery Flare Gas Recovery and Flare Systems**

A header for collection of vapor streams is included as an essential element of nearly every refinery process unit. These headers are commonly referred to as flare gas headers because they are typically connected to a flare system. However, at many refineries, including the Benicia Refinery, most of the gases sent to a flare gas header are normally routed away from the flare(s) and recovered using a flare gas compressor(s) to send the gases to a fuel gas unit where they become fuel for the refinery's furnaces, boilers, and other combustion devices. At most refineries, the quantity of gas in the flare header needing recovery is relatively small in comparison to the total quantity of fuel gas produced at the refinery. However, it is in the economic interest of the refinery to recover even this small fraction of gas instead of sending it to a flare, because these recovered gases offset the need to purchase additional fuels such as natural gas.

The primary function of the flare gas header is safety. It provides the processing units with a controlled outlet for any excess vapor flow, nearly all of which is flammable, making it an essential safety feature of every refinery. Each flare gas header also has connections for equipment depressurization and purging for maintenance activities including startup, shutdown and turnaround. Pressure relief devices are also routed to the header system to handle process upsets, malfunctions, emergency and other safety-related releases. By routing any excess collected gases through a flare, the majority (greater than 98 percent) of hydrocarbons in the gases are destroyed and converted to combustion byproducts (primarily water and CO<sub>2</sub>) before reaching the environment.

It is common practice for a flare gas header to incorporate hydrocarbon liquid knockout (KO) drums for separation and removal of entrained hydrocarbon liquids from the gas stream. This minimizes the possibility of hydrocarbon liquid being carried forward to a flare gas compressor or any of the flares associated with the header. Hydrocarbon liquid will result in severe mechanical damage to

most types of compressors and cannot be safely and completely burned in a flare. The vapor stream from a unit KO drum is then routed to the central refinery flare gas recovery system. The KO drum and header system may serve one process unit, or may serve a number of units in one integrated system.

A typical central refinery flare gas recovery system consists of a series of branch lines from various unit collection systems which join a main flare gas header. The main flare gas header is in turn connected to one or more flare gas compressors and to one or more flares. Normally, all vapor flow to the flare gas header is recovered by a flare gas compressor(s), which routes the gases to a fuel gas treatment scrubber(s) where contaminants such as sulfur are removed. Process gasses that are generated in excess of what can be handled by flare gas compressor(s), treatment scrubbers(s) and/or fuel gas consumers flow to a refinery flare where they are safely disposed of by combustion.

A water seal drum is typically located at the base of each flare to serve several functions. A water level is maintained in the seal drum to create a barrier which separates or "seals" the flare gas header from the flare. The flare gases must pass through this water in order to get to the flare. The depth of liquid maintained in the seal determines the pressure that the gas in the flare gas header must reach before it can "break" the seal and enter the flare. This creates a positive barrier between the header and the flare, ensuring that so long as the flare gas recovery system can keep pace with net gas production, there will be no flow from the flare gas header to the flare. It also guarantees that a positive pressure will be maintained at all points along the flare gas header, eliminating the possibility of air leaking into the system which could create an explosive atmosphere. Finally, the seal drum provides a positive seal to isolate the flare, which is itself an ignition source, from the header and the process units. Some flare gas recovery systems combine multiple flares with a range of water seal depths, effectively "staging" operation of the various flares.

Gases exit the flare via a flare tip which is designed to promote proper combustion over a wide range of gas flow rates. Steam is often used to improve mixing between air and hydrocarbon vapors at the flare tip, improving the efficiency of combustion and reducing smoking. A properly designed flare tip will also help to minimize noise levels during flaring events.

A small amount of fuel gas or natural gas continuously flows to each flare for two reasons. First, the pilots on the flare tip are kept burning at all times to ignite any gas flowing to the flare. Additionally, for some flare systems, a small purge gas flow is required to prevent air from flowing back into the flare stack.

Properly designed and operated flare systems destroy at least 98 percent of the hydrocarbon compounds that reach them, producing combustion products of CO<sub>2</sub> and water. Other combustion products include sulfur oxides (SO<sub>2</sub>) if there are sulfur compounds in the flared gases and small quantities of nitrogen oxides (NO<sub>x</sub>).

### **1.1.4 Typical Sources of Flow into Flare Gas Recovery Systems**

The sources of normal or base level flow to a refinery flare gas collection system are varied, but in general result from many small sources such as leaking relief valves, instrument purges and pressure control valves for refinery equipment items (e.g., overhead systems for distillation columns). Added to this low level base load are small flow spikes from routine maintenance operations, such as clearing hydrocarbon from a pump or filter by purging the volatiles to the flare gas header with nitrogen or steam. Additional flare load can also result from routine process functions often related to operation of batch or semi-batch equipment, for example, the regeneration procedures performed at catalytic naphtha reforming units which involve periodically removing hydrocarbon residuals from catalyst beds via a variety of procedures and directing the resulting gases to the recovery header.

Also, scheduled maintenance activities often result in higher flows to the flare gas recovery system. Equipment being prepared for maintenance must be essentially free of hydrocarbons before opening. This is necessary for both safety and regulatory reasons, including compliance with Regulation 8-10. Typical decommissioning procedures include multiple steps of depressurization and purging with nitrogen or steam, neither of which is suitable for recovery as fuel gas, to the flare gas header.

Although maintenance-related flows can be at times large, the ultimate design and sizing of refinery flare systems is, without exception, driven by the need for the safe disposal of much larger quantities of gases during emergencies and process upsets. A major emergency event, such as a refinery power failure, requires the safe disposal of a very large quantity of gases during a very short period of time in order to prevent a large increase in system pressure and avert a serious accident, hazard, or release of refinery gas directly to the atmosphere. The flows that the flare system manages during an event of this type are several orders of magnitude greater than the normal or baseline flow rate.

## **1.2 Benicia Refinery and Flare Gas Recovery Overview**

An overview of the Benicia Refinery operations and configuration is provided in this section, along with a description of the refinery Flare Gas Recovery System and associated flare systems. The information provided here is to assist with the general understanding of the refinery operations. The specific technical details required for compliance with Regulation 12-12-401 are provided in Sections 2 through 5.

### **1.2.1 Benicia Refinery Overview**

The Benicia Refinery is a modern petroleum refining facility, with a crude throughput rate of approximately 135,000 barrels per day (BPD) making it a moderate sized refinery compared with typical US facilities. The refinery produces a range of refinery products including propane, butane, gasoline, jet fuel, diesel fuel and fuel oil. The Valero Benicia Asphalt Plant (BAP) also operates on the site producing different grades of paving asphalts.

Major processing systems in the refinery include atmospheric crude distillation and vacuum crude distillation at the Pipestill (PS), hydrocracking (HCU), fluid catalytic cracking and distillation (FCCU), cat feed hydrotreating (CFHT), fluid coking and fractionation (CKR), light ends distillation (VLE and CLE), naphtha and distillate hydrotreaters (VNHF, LCNHF, HCNHF, JHF and DHF), catalytic naphtha reforming unit (NRU), motor gasoline reformulation (MRU), alkylation (ALK), dimate (DIM) and fuels storage and blending or Oil Movements (OMS). The facility also operates a hydrogen production plant (H2U), electrical power and steam production plant (COGEN), a sulfur gas unit (SGU) and tail gas unit (TGU) for recovery of sulfur, a wastewater treatment plant (WWT), shipping and marketing terminals, and utilities (UTIL) that support operations of the refinery complex. The refinery configuration is typical for an upgrading or fuels producing facility. A simplified operations flow diagram is provided in Figure 1.

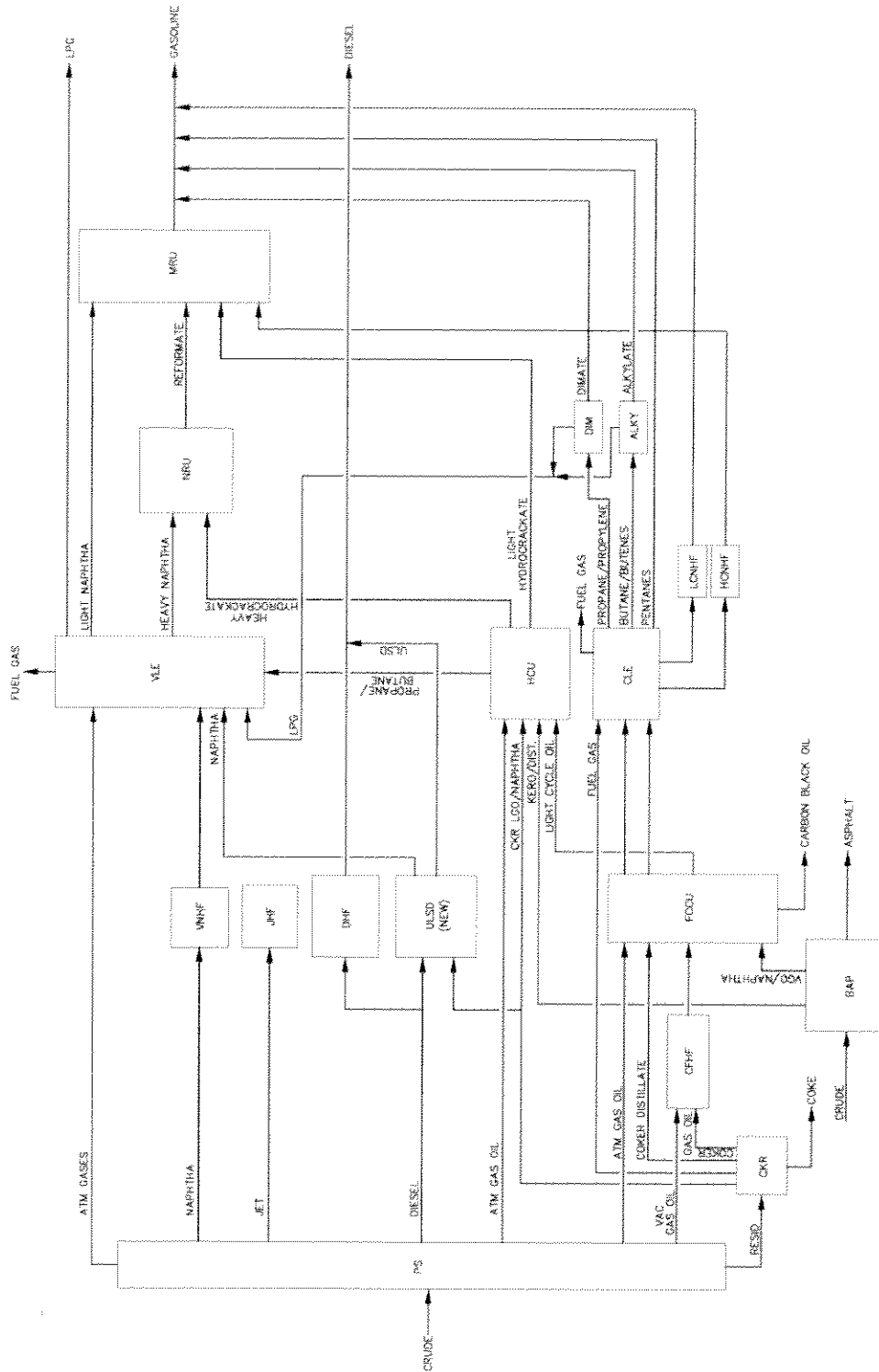
One unique feature of the refinery is that it was designed with the processing units highly integrated with each other. This approach maximizes energy efficiency and minimizes the storage of intermediate products; however, it also results in the refinery as a whole functioning essentially as one integrated unit. When one of the major, central processing units such as the PS is taken out of service, the entire refinery generally is also taken out of service at the same time.

### **1.2.2 Benicia Refinery Fuel Gas Unit Overview**

The Benicia Refinery maintains a single Fuel Gas Unit which must balance the demands of the fuel consumers within the refinery with the fuel gas produced by the refinery. The Fuel Gas Unit is also closely integrated with the refinery's hydrogen system, which like fuel gas is both produced and consumed within the refinery. Excess hydrogen can be returned to the Fuel Gas Unit within certain limits on quality and quantity.

The major users of refinery fuel gas include furnaces, boilers, four process gas turbines, and the COGEN plant. All of the users require the fuel gas to have a sufficient level of heating value (Btu content) to sustain proper combustion, particularly in burners that are specially designed to minimize the generation of NO<sub>x</sub> emission (e.g., low NO<sub>x</sub> burners). The sulfur content of the fuel gas must also be limited to minimize the formation of SO<sub>2</sub> emissions when burned. Most of the refinery gases contain some amount of sulfur, so they are collected and treated to reduce sulfur levels (by amine absorption) with subsequent recovery of the sulfur at the SGU.

**Figure 1**  
**Benicia Refinery Simplified Operations Flow Diagram**



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Different operations in the refinery produce fuel gases of different qualities. These are usually segregated to produce specific refinery products or intermediate streams. The atmospheric distillation (PS), NRU, and hydroprocessing units (CFHF, VNHF, LCNHF, HCNHF, DHF, JHF, ULSD and front end of HCU) produce gases that are primarily saturated hydrocarbon compounds which are separated into propane, butane, and gasoline range materials, and light ends which are routed to the Fuel Gas Unit. Heavy oil upgrading processes (primarily the CKR and FCCU) produce gases that contain significant amounts of unsaturated hydrocarbons (olefins) which are processed into fuel gas for internal use, chemical feedstocks (e.g., propylene and butylene), or are reacted further to produce gasoline range materials (e.g., dimate and alkylate).

Managing the fuel gas balance is a complex process, given the variety of gases produced and the stringent requirements for fuel gas quality by the consumers. The balance is further complicated by the fact that at the Benicia Refinery, both the producers and users are highly integrated and need to be brought into or out of operation in a coordinated manner. The process of starting up or shutting down major process units can itself take several days. The Fuel Gas Unit must balance loads constantly and quickly, and this is achieved by adjusting and maintaining the flow of makeup sources of fuel to the system including imported natural gas and by vaporizing liquid fuels (e.g., propane and butane). During periods of excess gas production or loss of major gas consumers, the excess gases are routed to the Flare Gas Recovery System and on to the flares for safe disposal until the balance can be restored.

The interrelationship between the Fuel Gas Unit, hydrogen system, fuel gas consumers, Flare Gas Recovery System and the flares is shown in a simplified block flow diagram provided in the following section.

### **1.2.3 Flare Gas Recovery System Overview**

The Benicia Refinery operates one main Flare Gas Recovery System with two flares (South and North) that fall under Regulation 12-12. The main refinery Flare Gas Recovery System collects sources from throughout the refinery and directs the gas to the Flare Gas Compressors. If there is excess flow, or if the gas quality makes it unsuitable for recovery, the gases flow to the two main refinery flares – the South Flare and North Flare. Flow of excess gases from the Flare Gas Header preferentially goes to the South Flare first, then to the North Flare if necessary, as managed by staged water seals at each flare. Gases are routed to both flares only during major flaring events when high rates of gas flow occur.

The second flare system is the Acid Gas Flare that primarily receives a few relief vents from the SGU which are high in hydrogen sulfide and ammonia. The Acid Gas Flare is not used as a part of major maintenance procedures, and is typically only used for emergency situations and safety reasons. Occasional and limited



use of the Acid Gas Flare is needed for startup, shutdown, and minor maintenance activities. This flare system only has infrequent flaring events, and in 2005 and 2006, no events reached reportable levels.

Additionally, there is an emergency dedicated flare for refrigerated butane storage at the Benicia Refinery which is exempt from the Regulation 12-12-401 FMP requirements pursuant to Regulation 12-12-110.

When developing on-going flare minimization procedures and preparing this FMP, the Benicia Refinery has focused primarily on the Flare Gas Recovery System and the associated South and North Flares because the Acid Gas Flare is primarily used during emergency/upset situations. Use of the Acid Gas Flare for non-emergency/upset situations is limited and resulting emissions relatively insignificant.

### 1.3 Flare Minimization History at the Benicia Refinery

The Benicia Refinery began implementing projects and procedures to minimize the frequency and magnitude of flaring events as far back as 1975. A review of the major flare minimization projects and procedures that have been implemented since that time is provided in Table 1. A complete listing of flare minimization projects and procedures is provided in Section 3 of this FMP.

**Table 1  
Major Flare Minimization Projects History 1975 to Present**

<b>Project</b>	<b>Year</b>	<b>Description/Comments</b>
Installed Fuel Gas Compressors	1975	Installed Fuel Gas Compressors (C-2201 A/B) and modified the Fuel Gas Unit to significantly reduce the refinery's use of purchased natural gas. As a result of this project, compression of low pressure fuel gas (LPFG) with the Stage 1 compressors is used to fuel the gas turbines. Additionally, the Stage 2 compressors are used for compression of low pressure tail gas (LPTG) which is used to feed the H <sub>2</sub> U. Prior to the installation of the Compressors, tail gas was let down to LPFG, which loaded up the LPFG system and caused flaring.
Installed Flare Gas Compressor	1976	Installed the first Flare Gas Compressor (C-2101 A) to provide recovery capacity of up to 6 mmscfd of flared gases. Prior to installation of this compressor, all gases sent to the Flare Gas Header were flared.
Installed second (spare) Flare Gas Compressor	1983	Installed the second Flare Gas Compressor to provide a spare compressor of the same capacity as the first recovery compressor. This spare compressor reduces flaring during compressor maintenance and unplanned compressor shutdown due to equipment failure or malfunction. Additionally, during high loading of the Flare Gas Header it is possible to operate both compressors in parallel and recover additional flare gas to the Fuel Gas Unit.

**Table 1  
Major Flare Minimization Projects History 1975 to Present**

<b>Project</b>	<b>Year</b>	<b>Description/Comments</b>
Reduced frequency of turnarounds	Early 90's to present	Numerous comprehensive projects and improvements were implemented to allow longer runs between turnarounds. Most refinery projects include an element of improved reliability which increases run length. Examples of reliability improvement projects include upgraded metallurgy, improved designs, and equipment replacements. Shutdown and startup associated with turnarounds generate significant quantities of gas that result in flaring. Increased run length between maintenance turnarounds results in less frequent flaring events from unit shutdowns and startups.
Upgraded condensers	90's to present	Upgraded condensers to improve performance during hot weather periods. This improved performance reduces production of fuel gas and decrease the likelihood of a fuel gas imbalance during hot weather periods. Examples of upgraded condensers include redesigned exchangers and additional surface area. Increased condenser capacity further cools the vapor stream and recovers additional light hydrocarbons, such as propane and butane, which would otherwise load up the Fuel Gas Unit and potentially cause flaring. Condenser upgrades have been implemented throughout the refinery, particularly in light hydrocarbon processing units such as VLE, CLE, and ALKY.
Revised turnaround procedures	1999 to present	Starting with the 1999 refinery-wide turnaround, a much higher emphasis was required for individual unit Process Coordinators of a major turnaround to minimize flaring by improving unit shutdown and startup procedures, scheduling, and flare balance. Additionally, a Refinery Coordinator position was created for major turnarounds to work out plans to stagger unit shutdowns and startups to minimize flaring. Flaring was significantly reduced during the 1999 refinery-wide turnaround and was then again significantly reduced during the 2004 refinery-wide turnaround.
C-701 reliability improvement	1999	Upgraded the Cat Gas Compressor (C-701) control systems to a Triconex system which greatly increases reliability. The improved reliability of C-701 reduces the potential for unplanned shutdown of C-701 that result in significant flaring from the FCCU.
Implemented Fuel Gas Seriatim	Late 90's to present	Both proactive and reactive operating procedures are identified in a Fuel Gas Seriatim to address flaring that may occur during hot weather. The operating procedures, which are regularly updated, typically include, cutting feed rates to the FCCU and/or CKR, cutting reaction temperature at the FCCU, and cutting makeup fuels to the Fuel Gas Unit.

**Table 1  
Major Flare Minimization Projects History 1975 to Present**

Project	Year	Description/Comments
Installed COGEN	2002	Installed COGEN plant which is a major fuel gas consumer, generates power, and produces steam for the refinery. The addition of the COGEN plant increased the refinery's usage of fuel gas, providing additional capacity for the reuse of recovered flare gases. The installation of COGEN, significantly reduces the likelihood of a refinery fuel gas imbalance that results in flaring. The addition of the COGEN plant also provides a third source of electric power to the refinery which reduces the likelihood of power outages (there are two power feeds from the PG&E grid). Power outages result in very significant flaring because the entire refinery is simultaneously shutdown and all process gases must be flared. Additionally, restarting the refinery after power has been restored also causes flaring.

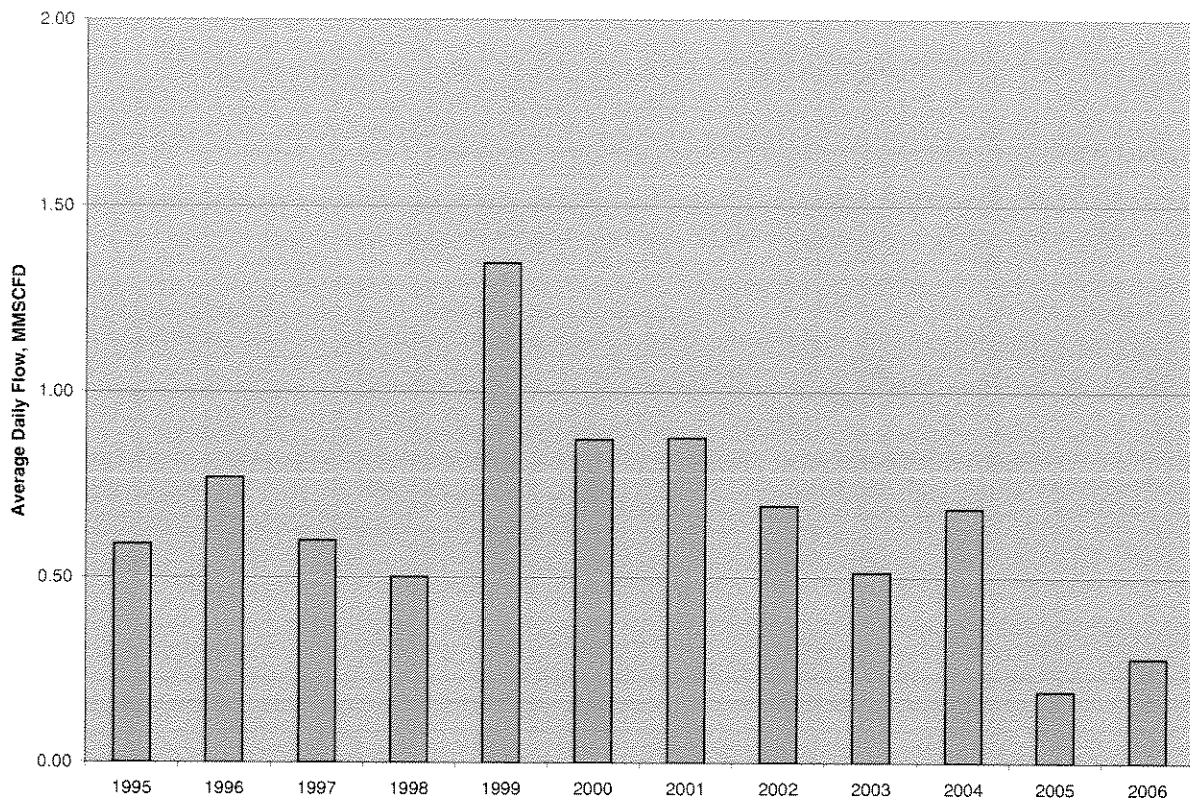
#### 1.4 Refinery Flare Gas Recovery and Flaring Events 1995-2008

Historical data summarizing the average rate of flow to the South and North Flares at the Benicia Refinery from 1995 to 2006 has been reviewed, and is presented in Figure 2a. The data come from refinery flare flow meters that have been operational on each flare since prior to 1995. This data may be slightly different from the flows reported to the BAAQMD since 2004 pursuant to Regulation 12-11, which are generated by new flow meters at a different location.

Despite the variable nature of flaring events, a general trend of improvement can be observed. For comparison purposes, these data are best considered in discrete periods of time, depending on whether a major turnaround or maintenance event occurred during the year. The years of 1995 to 1998, 2000 to 2003, and 2005 to 2006 represent operations without a major refinery-wide turnaround or maintenance activity. For these periods, flows averaged 0.61, 0.74, and 0.24 mmscfd, respectively. The most recent flaring rates for 2005 and 2006 represent a reduction of more than 50 percent of the average flow in previous non-turnaround years. This reduction was achieved as a result of the mechanical and procedural improvements identified in Table 1.

The higher average rates of flaring in 1999 and in 2004 correspond to major refinery-wide maintenance events (turnaround), in which essentially all refinery units were shutdown, maintained, and restarted. Again, the refinery's recent operations demonstrate a reduction of nearly 50 percent (from an average of 1.35 to 0.69 mmscfd) in flaring emissions from 1999 to 2004.

**Figure 2a**  
**Flows to South and North Flare 1995 to 2006**



It should be noted that to provide a consistent historical review, the flare meters that were in place from 1995 to the present have been used as the source of flow data. In 2004, new, flow meters were added to comply with the Regulation 12-11 requirements<sup>4</sup>. The recorded average daily rate data for the previously existing and new flow meters was compared for the years 2005 and 2006, and found to be sufficiently consistent (deviating by less than 10 percent) for the presentation of data in this manner.

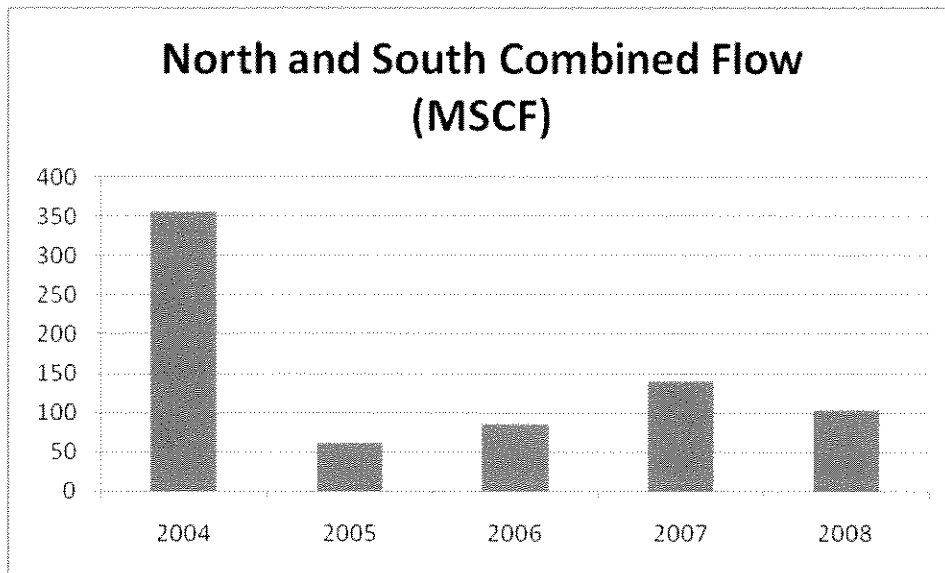
Historical data summarizing the flow to the South and North Flares at the Benicia Refinery from 2004 to 2008 has been reviewed, and is presented in Figure 2b. The data come from refinery flare flow meters that were installed in 2004 per District regulations.

Despite the variable nature of flaring events, a general trend of improvement can be observed. For comparison purposes, these data are best considered in discrete periods of time, depending on whether maintenance (turnaround) was occurred during the year.

<sup>4</sup> Review of flaring events prior to 2004 provides limited information. Since the previous meters were not used for regulatory purposes, flaring event durations and volumes cannot be specified with certainty. In many cases, predominate causes of flaring cannot be reliably determined due to limited documentation and the elapsed time since the flaring event.

The years of 2005, 2006 and 2008 represent operations without major refinery-wide maintenance activities. During these three years, flaring was significantly reduced over previous years without major refinery-wide maintenance activities. In 2004, a major refinery-wide maintenance event (turnaround) was conducted in which essentially all refinery units were shutdown, maintained, and restarted. In 2007, a significant maintenance event (mid-cycle turnaround) was conducted in which a significant number of refinery units were shutdown, maintained, and restarted. Both the 2004 and 2007 turnaround years had reduced flaring over the previous turnaround years.

**Figure 2b**  
**Flows to South and North Flare 2004 to 2008**



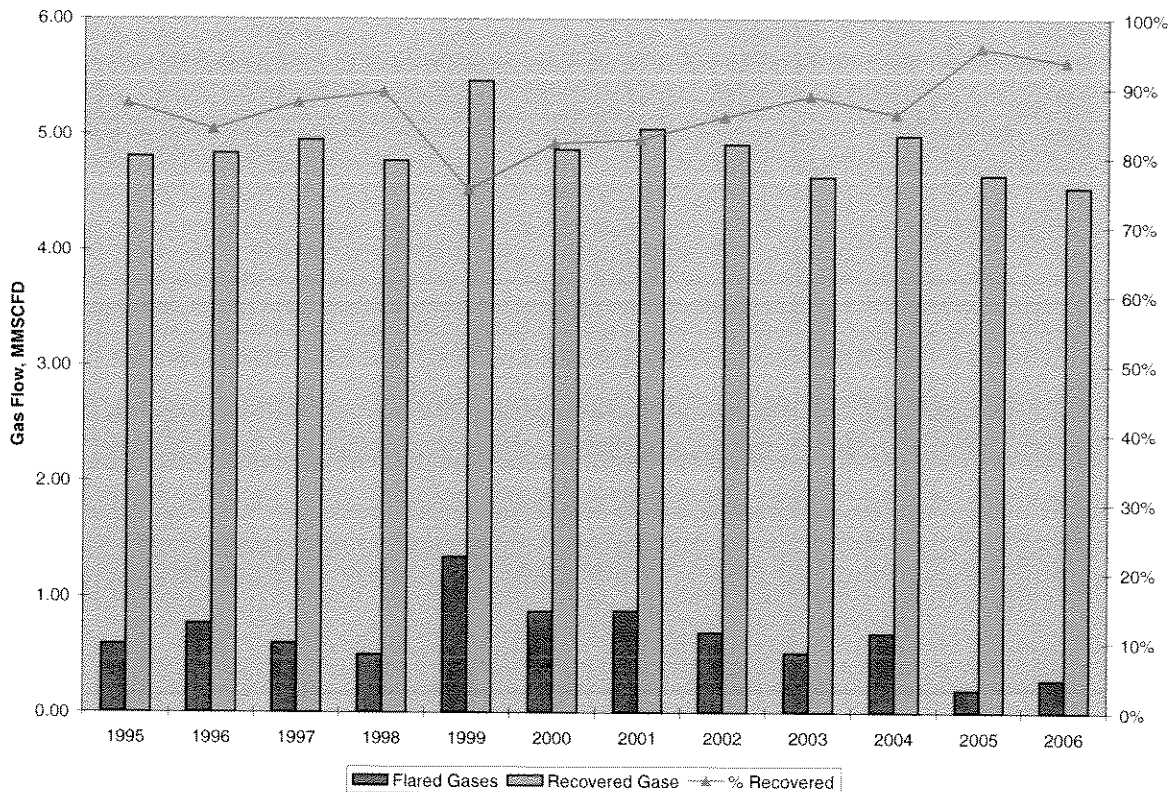
These reductions are even more significant considering they were achieved after 2004, the year that the Vessel Depressurization Rule (Regulation 8-10) came into effect. This rule significantly increased quantities of vapors directed to the Flare Gas Recovery System by requiring gases from depressuring of process vessels be directed to the Flare Gas Header until very low levels of hydrocarbons are present. The gases that are recovered in this manner are low in Btu value (essentially all nitrogen), and can be unsuitable for recovery and reuse for this reason. Section 1.9 discusses further the impact of balancing a number of environmental objectives on the flare minimization procedures, especially because the Flare Gas Recovery System and associated flares have been a preferred destination for hydrocarbon vapors that are being captured in increasing quantities as a result of improved operating procedures and maintenance practices.

To demonstrate the benefits of the Flare Gas Recovery System, the average rate of recovered gases from 1995 to 2006 was evaluated and is shown in Figure 3. In this figure, the average rate of flared gas recovery is shown next to the flow of gases to the flare each year. The Flare Gas Recovery System recovered an average of 4.2 mmscf/d, or 87 percent of all gases routed to the Flare Gas Header during the period of 1995 to

2006. For the more recent period of 2002 to 2006, an average of 90 percent of all gases that flowed to the Flare Gas Header were recovered.

The Flare Gas Recovery System is used to recover an average of about 4 to 5 mmscfd of gas from the Flare Gas Header. This recovered flare gas is sent to the Fuel Gas Unit along with other fuel-quality gases produced by various process units and purchased gases such as natural gas. The Fuel Gas Unit treats and delivers an average of about 75 mmscfd of fuel gas (scrubbed to remove sulfur compounds, primarily hydrogen sulfide) which is used to fire refinery furnaces, boilers, gas turbines, and COGEN. There is an economic incentive to recover flare gas and to avoid flaring because every Btu of recovered flare gas displaces a Btu of purchased gas.

**Figure 3**  
**Flare Gas Recovery from South and North Flare 1995 to 2006**



The Benicia Refinery flare gas recovery/flaring performance has also been evaluated in comparison with data that is publicly available for typical refinery operations in the United States, and for refineries that are located in the Bay Area. The data for other US refineries are limited, except for those located in the Bay Area as the BAAQMD posts the results of monthly reporting on its web site.

Flaring data from the Midwest Regional Planning Organization (MRPO), representing thirteen Midwest refineries and from the Texas Commission for Environmental Quality (TCEQ) for the refineries located in the Houston-Galveston area were reviewed. In

each case, the data were provided as an aggregate of all facilities and generally were not suitable for a direct comparison on a facility to facility basis. However, qualitative results that were drawn from this evaluation include:

- The Bay Area refineries on average produced approximately 10 percent of the SO<sub>2</sub> emissions of similar sized facilities in the Midwest, and the Benicia Refinery produced approximately 5 percent of the SO<sub>2</sub> emissions as the Midwest refineries, when adjusted for capacity.
- The Bay Area refineries, on average, produced approximately 20 to 50 percent of the VOC emissions of facilities in the Houston-Galveston area, and the Benicia Refinery produced approximately 15 to 40 percent of the VOC emissions on a capacity-adjusted basis. This is based on a comparison of non-methane hydrocarbon emissions with the stated VOC rates, a conservative approach.

Because of the incompleteness of this data, the qualitative conclusion is that Bay Area refineries are performing significantly better than the typical US facility in the area of flare minimization.

The other region of the country with similar flare minimization regulations in place at this time is the Los Angeles area. Rule 1118 developed by the South Coast Air Quality Management District is similar to Regulation 12-12 in many ways. A search of refinery flaring data was conducted, but data for the Los Angeles area refineries operating under Rule 1118 were not available.

The most comprehensive refinery flaring data that was available was found on the BAAQMD website for the five Bay Area refineries. The data show that the Benicia Refinery's average flared gas rate of 0.1 mmscfd was less than half the average of the other Bay Area refineries (0.44 mmscfd). Because each refinery in the area is a different size, the flaring data have been normalized on a nameplate crude throughput basis so that emission rates are shown on a consistent basis with the size of the Benicia Refinery (135,000 bpsd). These data was evaluated for 2005 for each of the refineries, and are presented in Table 2 in a manner which does not identify the other refineries by name.



**Table 2**  
**Summary of BAAQMD 2005 Flaring Data for Bay Area Refineries**  
**(rates adjusted for capacity of 135,000 bpsd)**

Facility	Flow Volume, mmscfd	Methane, tpy	Non-methane Hydrocarbons, tpy	Sulfur Dioxide, tpy
Refinery A	0.18	7.9	10.8	45.3
Refinery B	0.34	8.1	26.2	4.1
Refinery C	0.68	15.4	22.8	41.4
Refinery D	0.23	10.6	56.6	37.9
Average of Other Bay Area Refineries	0.36	10.5	29.1	32.3
Benicia Refinery	0.19	4.7	27.2	19.0
Benicia Refinery (Percentage of Average)	53%	44%	94%	59%

This information shows that the Benicia Refinery's flaring levels are better than the other average Bay Area facilities in all categories, even after adjustment based on the size of each facility. The Benicia Refinery's efforts in flare minimization can be seen to have had a positive effect in this good performance relative to its peer facilities, especially in light of the fact that the Bay Area refineries, as a group, appear to set the refining industry's best practices for flare minimization activities.

The Acid Gas Flare did not have any events in 2005 that exceeded the reportable volume limits (0.5 mmscfd), and historical data has not been provided for that flare in this overview section. Complete flare system information as required by Regulation 12-12-401 is provided in Sections 2 through 5.

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### **1.5 Typical Base Load Conditions to the Flare Gas Header**

For a variety of reasons, gases are routinely sent to the Flare Gas Header (but not necessarily to the flare) even when there are no maintenance activities, equipment failures or malfunctions, emergency conditions, and/or safety issues. This regular flow to the Flare Gas Header represents a base load condition that is typically between



about 3 to 5 mmscfd. Examples of sources that can contribute on a regular or continuous basis to the Flare Gas Header include, but are not limited to:

- Sampling purges;
- Analyzer purges;
- Leakage of relief valves;
- Vents from seal pots used to control air emissions from pump seals;
- Low pressure tankage or vessels vented to Flare Gas Header for air pollution control and/or odor control purposes;
- Accumulation of small operational actions or maintenance procedures each of which results in production of flare gas;
- Low pressure equipment vented to Flare Gas Header (e.g., tower overhead systems);
- Routine reactor depressurization at the NRU as a part of the cyclic catalyst regeneration process; and
- Loading and unloading operations at the light ends loading racks.

### **1.6 Current Reasons for Flaring**

While the results of the ongoing flare minimization procedures can be seen in this review of recent fuel gas flow and recovery data, there are still circumstances during which flaring remains a preferred or required option. These flaring events can be summarized as falling under, but not limited to, one or more of the following broad categories:

- maintenance activities including process unit startup, shutdown, and turnaround events;
- fuel gas quantity and quality issues such as a fuel gas imbalance or out of range fuel gas heating value (Btu);
- equipment failure and malfunction including process upsets;
- emergency conditions beyond the reasonable control of the Benicia Refinery or its operators caused by sudden, infrequent, and not reasonably preventable equipment failure, natural disaster, acts of war or terrorism, external power curtailment, loss of utilities (e.g., power, cooling, steam, and instrument air), or fire; and
- safety – to prevent an accident, hazard, or release of vent gas directly to the atmosphere.

This above listing of broad categories of flaring events reflects the varied nature and many potential causes of flaring. The broad categories are intended to cover the range of conceivable flaring events that could potentially occur at the Benicia Refinery as required by Regulation 12-12-301. Further specific examples of types of flaring events associated with maintenance activities, fuel gas quantity and quality, and equipment failure and malfunction are provided below to assist in the understanding of the Flare Gas Recovery System and its critical role in refinery operations. This listing is not intended to be fully comprehensive of all specific potential relief events, but generally demonstrates the types of events that could occur.

### 1.6.1 Planned and Unplanned Maintenance Activities

Planned major maintenance activities including process unit startup, shutdown, and turnaround events are required for all of the refinery units, typically on at least a five to six year turnaround cycle. Some units such as CKR, hydrofiners, HCU, ALKY, NRU, DIM, and portion of the PS are maintained outside of the major turnaround cycle. Planned minor maintenance activities including partial or total unit shutdown, slowdown, equipment isolation, and/or startup can occur at any time for any process unit. Unplanned process unit shutdown for maintenance occurs on an infrequent basis, and although some units may withstand more events than others, any unit may be subject to unplanned events at some point in time.

Some examples of flaring associated with maintenance activities including process unit startup, shutdown, and turnaround events are provided below. It should be noted that flaring as a result of some of these maintenance activities may also be caused by fuel gas quantity and/or quality issues discussed in the next section.

- Maintenance, startup or shutdown events where the volume of gases sent to the Flare Gas Header is too large to be completely recovered by the Flare Gas Compressors.
- Maintenance, startup, or shutdown events where gases are routed to the flare system with a high nitrogen or hydrogen content and insufficient heating value for safe reuse in the Fuel Gas Unit.
- Maintenance, startup or shutdown events where the fuel gas production is not in balance and sufficient users do not exist to take all of the recovered fuel gas.
- Maintenance, startup or shutdown events where the hydrogen gas system may not be in balance and users do not exist to consume the available hydrogen.
- Maintenance, startup or shutdown events where gases are produced that do not have a composition that is satisfactory for safe combustion in furnaces, boilers, gas turbines, and COGEN. Examples include gases with high hydrogen or nitrogen content, high steam content, low heating value (Btu content), and other incompatible constituents. If the heating value (Btu content) of flare gas is too low for recovery, the refinery must add fuel gas to the Flare Gas Header to ensure that there is sufficient heating value at the flares to ensure that any residual hydrocarbons are effectively combusted and the flare device is not extinguished.
- During shutdown, vessels and other process equipment are depressurized and may be purged with nitrogen, hydrogen, and/or steam prior to opening in accordance with Regulation 8-10.

- Startup or shutdown where one or more major fuel gas consuming or flare gas processing components (e.g., Flare Gas Compressors, COGEN, or a major furnace) cannot operate for a period of time.
- Shutdown procedures where nitrogen or other gases may be needed to cool reactors.
- Catalyst change-outs, which may include the need to strip hot catalyst with hydrogen or nitrogen, cool hot catalyst beds, and free the vessels of hydrocarbons before opening. Some catalysts that are pyrophoric in nature require even further special processing to maintain them in an inert oxygen free environment.
- Conditioning of replacement catalyst with sulfur compounds prior to startup which may generate more fuel gas and/or hydrogen than can be managed in the Fuel Gas Unit and/or more hydrogen sulfide than can be treated by the Fuel Gas Unit.
- Startup procedures where high pressure vessels must be slowly heated prior to “pressuring up” the vessel to prevent metal failure events (e.g., brittle fracture), which result in directing hot inert gases to the Flare Gas Recovery System.
- Startup sequencing procedures where processing units (e.g., FCCU) may need to be restarted before the downstream gas processing units (e.g., CLE) can be brought into service.
- Planned or unplanned maintenance activities for the COGEN unit. This unit has been a critical component of the flare minimization program. However, it can require major maintenance approximately every six months. It is also subject to the periodic outages associated with all major equipment. During these outages, the normal fuel gas balance in the refinery is dramatically impacted, and measures must be taken by the refinery to bring the system back into gas balance.

As noted above, refinery maintenance activities can create the need to divert nitrogen and/or hydrogen rich gases that are produced during maintenance away from the Flare Gas Compressor to a flare. This is a necessary result of the maintenance procedures which have been adopted to minimize the release of hydrocarbons to the atmosphere during equipment opening, and is in fact desirable, as any hydrocarbons in the gases are effectively combusted in the flare system. It should be noted that both nitrogen and hydrogen do not produce undesirable compounds upon combustion (excluding a very low potential quantity of NO<sub>x</sub> compounds). Some maintenance activities can also utilize steam, which can also impact the Flare Gas Recovery System. The need to divert gas to the flare is generally driven by the quantity and composition of the gases produced during maintenance, including startup, shutdown, and turnaround.

Fuel gas composition can have a significant impact on the equipment in the Flare Gas Recovery System, at the downstream Fuel Gas Unit and at the fuel gas consumers. A summary of these potential impacts are provided below:

- High nitrogen or hydrogen content can impact furnaces, boilers, gas turbines, and COGEN by producing a low Btu gas that potentially could cause flameout and/or instable operation.
- High nitrogen or hydrogen content can impact the capacity of flare gas compressors if they are designed for a significantly different molecular weight.
- Hydrogen and other low molecular weight gases can impact flare gas compressor performance by reducing capacity, and may cause overheating or the inability of the compressor to operate.
- Low Btu content (often caused by high levels of nitrogen or hydrogen) can also impact NO<sub>x</sub> controls, particularly at gas turbines which are very sensitive to fuel heating value.
- Steam can impact compressors by raising the inlet temperature significantly, and potentially causing overheating or a high temperature shutdown.
- Steam can impact knock out drums by condensing and filling them with liquid, as well as increase sour water production.

Each of these impacts is discussed further below:

#### **1.6.1.1 High Nitrogen Content**

High nitrogen content in the recovered gases presents a range of problems both at the users of recovered fuel gas and at the Flare Gas Compressors themselves.

High flows of nitrogen from equipment decommissioning can lead to a much higher than normal inert content in the mixed flare gas, greatly reducing its fuel value (measured as Btu/scf). When this low Btu flare gas is transferred to the fuel gas header, the lower fuel value can have the effect of reducing combustion efficiency, as the burners are designed to operate with fuels that have a higher heat content per cubic foot. In extreme cases, the heating value of the gas can be reduced by dilution with nitrogen to the point of extinguishing the burner flame. This creates the potential for unburned fuel to accumulate in the furnace or boiler, leading to an explosion when it is re-ignited. NFPA 85 – Boiler and Combustion Systems Hazards Code and NFPA 86 Standards for Ovens and Furnaces warn against this possibility.

Higher than normal nitrogen content of flare gas that can result from nitrogen purging, can also increase the molecular weight (28 for nitrogen versus 16 for natural gas/methane) of recovered gases and potentially create problems with the Flare Gas Compressor. Reciprocating

compressors increase the pressure of a constant inlet volumetric flow rate of gas, so for a given volume of gas an increase in molecular weight can result in an increase in the mass that is compressed. This increases the work that the compressor has to do, which can overload and/or damage the compressor and its ancillary equipment (e.g., motor, shaft, bearings, etc.).

Additional problems can occur for high molecular weight gases in multi-stage compressors. For most Flare Gas Recovery Systems the compression ratio (ratio of outlet pressure to inlet pressure) is high enough that more than one stage of compression is needed. The temperature of the gas increases as it is compressed, and the gas is cooled between stages in order to control the temperature increase. Operation of a reciprocating compressor with a feed stream that has a molecular weight outside of the range for which it was designed can lead to a temperature increase exceeding the design limitations of the machine.

#### **1.6.1.2 Hydrogen and/or Low Molecular Weight Gases**

There is also the potential for much lower than average molecular weight recovered gas if increased flows of hydrogen occur. There are many process and reactor systems within the refinery that contain gases with high hydrogen content. When this equipment is decommissioned by depressurization to the flare gas header, there can be a sharp decrease in the flare gas' average molecular weight. Compressors are limited in their ability to function at significantly lower-than-design molecular weights, and mechanical damage, overheating or other malfunctions can occur. Hydrogen is also used for some catalyst cleaning, or "hot stripping" processes to remove residual hydrocarbons.

#### **1.6.1.3 High Steam Content**

A major advantage of using steam to clear hydrocarbons from equipment is its elevated temperature. However, this can be a disadvantage with respect to flare gas recovery. When the distance the gas must travel to reach the flare gas compressor is large, (the Flare Gas Header is long), the gas will cool, and much of the steam will condense and be removed as water at the knock-out drum. However; with a shorter flare line or a long-duration steam out event, the temperature of the flare gas at the flare gas compressor can be elevated significantly. If the temperature of the flare gas stream at the inlet to the flare gas compressor exceeds machine limits, the gas must be diverted away from the compressor inlet in order to avoid mechanical damage. High temperature limits can also be exceeded within the stages of the compressor if the feed gas temperature is too high.

Another disadvantage of the use of steam is that most of what is added as a vapor will condense in the flare gas headers and must be removed via the water boot of a knock-out drum, either as the result of cooling as it

flows through a long flare line or in a chiller/condenser included specifically for removal of water vapor from the flare gas. Either way a sour water stream is produced which will require treatment.

### **1.6.2 Fuel Gas Quantity and Quality**

In general, flaring can occur as a result of fuel gas quantity and quality issues if (1) the quantity of fuel gas generated is larger than can be managed by the Flare Gas Compressors, Fuel Gas Unit, and/or fuel gas consumers; or (2) the quality (composition) of fuel gas is such that it must be routed to the flare because it cannot be utilized by the fuel gas consumers for a variety of reasons which may include safety, stringent gas turbine specifications, and to ensure low NO<sub>x</sub> performance. When flaring is caused by fuel gas quantity and quality issues, the general cause is often maintenance activities, equipment failure and malfunction, emergency situations, and/or safety reasons. As discussed above, there is always a base-load to the Flare Gas Header. Therefore, flaring can also occur as a direct result of fuel gas quantity and quality issues (i.e. the general cause is not maintenance activities, equipment failure and malfunction, emergency situations, and/or safety reasons).

Examples of flaring that may be caused by fuel gas quantity and quality when maintenance activities and equipment failure, or malfunction are the general cause are provided in preceding and proceeding sections, respectively. Some examples of flaring that may be caused by fuel gas quantity and quality that are not a result of maintenance activities, equipment failure and malfunction, emergency situations, and/or safety reasons are listed below:

- Production of off spec or excess light liquid products in excess of the capacity of the Flare Gas Compressors, the Fuel Gas Unit, and/or the fuel gas consumer's capacity to utilize all of the fuel gas.
- Daily and seasonal fluctuations in temperature which reduce condensing capacity (air cooling with fin-fans) and can cause significant increased production of light gases.
- Elevated gas production rates for the hydroprocessing or reforming units when operating near the "end-of-run" (the period just prior to unit turnaround);
- Seasonal changes in market demand for products that may result in decreased markets for light products and gases such as propane and butane.
- Operations where gases are produced that do not have a composition that is satisfactory for safe recovery to the Fuel Gas Unit. Examples include, but are not limited to, high hydrogen or nitrogen content, high steam content, low heating value (Btu content), and other incompatible constituents. If the heating value (Btu content) of gases is too low for recovery and use in the Fuel Gas Unit, the refinery must add significant quantities of fuel gas to the Flare Gas Header to ensure that there is

sufficient heating value at the flares to ensure that any residual hydrocarbons are effectively combusted and the flare is not extinguished.

### **1.6.3 Equipment Failure and Malfunction**

Non-recurrent equipment failure and malfunction including process upsets are considered to be emergency conditions as defined by Regulation 12-12-201. In accordance with Regulation 12-12-301, flaring as a result of emergency conditions is allowed and emergency conditions do not need to be included in the FMP. However, the Benicia Refinery has elected to include equipment failure and malfunction including process upsets in this FMP to help minimize the frequency and magnitude of flaring during these events and to learn from these events so as to reduce the likelihood of recurrent failure. Examples of flaring associated with equipment failure and malfunction including process upset, include, but are not limited to, the following:

- Flaring can be caused by failure or malfunction of major and/or minor equipment such as compressors, cooling systems, electrical switching equipment, pumps, valves, and instrumentation. Rotating equipment in the difficult services that exist in a refinery will always have a finite service factor, even when maintained at or better than industry standard levels of reliability. Even with an effective preventative maintenance program in place, equipment failures will at times still occur.
- Equipment failure and malfunction, including process upsets, can result in the need to quickly depressure vessels and other process equipment to the Flare Gas Header. This often results in a situation where the capacity of the Flare Gas Compressors and/or the Fuel Gas Unit is not sufficient to process all of the gas that is generated. As a result, the flares may be used to safely combust excess gases.
- Flaring can be caused by a complete or partial loss of a major utility such as cooling water, electrical power, steam production, and instrument air. These type of events can significantly impact refinery gas condensing capability which is likely to result in the generation of more gas than can be managed by the Flare Gas Compressors and/or Fuel Gas Unit.
- Malfunction or loss of a compressor (or ancillary equipment item) used to process refinery gases (Cat Gas Compressor, Coker Gas Compressor). Reduced capacity or loss of this equipment can result in significant flow of gases to the Flare Gas Recovery System until the plant is returned to its normal mode of operation and/or the equipment can be repaired.
- Malfunction or loss of an online Flare Gas Compressor can have a significant impact on the ability to recover fuel gas. Because of the difficult service for these compressors, the off-line compressor must typically be maintained or repaired before it is available as a spare compressor. As a result, even though the Benicia Refinery has a backup Flare Gas

Compressor, it is possible that both compressors could be offline at the same time. For example, if the reliability and required maintenance of the compressors is such that they have each have 95 percent online availability, statistically they would both be offline 0.25 percent of the time or about one day per year.

- Process or equipment failure or malfunction of the fuel gas treatment scrubbers, the amine regenerator, SGU, TGU, and/or associated equipment.

For the emergency situations listed above, it is critical that the refinery flare systems are available to safely dispose of large quantities of gases that may be generated. The flares prevent these gases from being released directly to the atmosphere and significantly reduce any potential safety and environmental impacts.

### **1.7 Current Flare Minimization Procedures**

The Benicia Refinery has a long history of implementing physical and procedural changes to improve the effectiveness of the Flare Gas Recovery System. While reductions of approximately 50 percent in flared gas volumes have been achieved in recent years (as discussed in Section 1.4), the Benicia Refinery continues to monitor the sources of flow to the Flare Gas Recovery System and continuously work to minimize the frequency and magnitude of flaring events. This ongoing process of improvement is a cornerstone of the refinery's flare minimization efforts. At the Benicia Refinery, flare minimization procedures include the following:

- **Planning Component**

For upcoming maintenance including startup, shutdown, and turnaround activities that could result in flaring, a planning component is used to maximize flare gas recovery and minimize the frequency and magnitude of any flaring. When the planning component is conducted, flare minimization techniques, practices, and lessons learned from previous review components are evaluated and considered.

- **Review Component**

When reportable flaring events occur, an analysis is conducted to evaluate the cause of flaring and potential feasible measures that can be incorporated into future operational, maintenance, or planning practices. This component is consistent with the Regulation 12-12-405 and 12-12-406 requirements for review of reportable events above identified threshold limits (0.5 mmscfd or 500 lb/day SO<sub>2</sub> emitted). For flaring events that do not exceed the thresholds for a formal analysis, lessons learned are still captured and incorporated into future planning.

- **Preventative Maintenance Component**

Preventative maintenance is needed to minimize the occurrence and frequency of equipment failure and malfunction which can ultimately lead to flaring. The adequacy of maintenance schedules and protocols have recently been reviewed



at the Benicia Refinery. If a recurrent failure were to occur that resulted in flaring, the Benicia Refinery would re-evaluate the adequacy of maintenance schedules and protocols.

These flare minimization activities are depicted in the flowchart provided in Figure 4. Inter-disciplinary teams are generally involved in the process, including members of the environmental, operations, engineering, and maintenance staffs as appropriate. This approach ensures that input from a variety of viewpoints is considered during the event review.

### **1.7.1 Planning for Maintenance Activities that May Result in Flaring**

One area in which the Benicia Refinery has achieved significant improvements is in the preparation for maintenance including startup, shutdown, and turnaround activities that may result in flaring. Operations supervisory personnel generally prepare and issue specific operating procedures each time a significant activity is conducted to ensure the activities are conducted safely, effectively, and with a minimum of impact on the environment. The procedures specifically consider safety and environmental precautions every time they are executed, including a review of any potential impacts on the Flare Gas Recovery System and the potential for flaring.

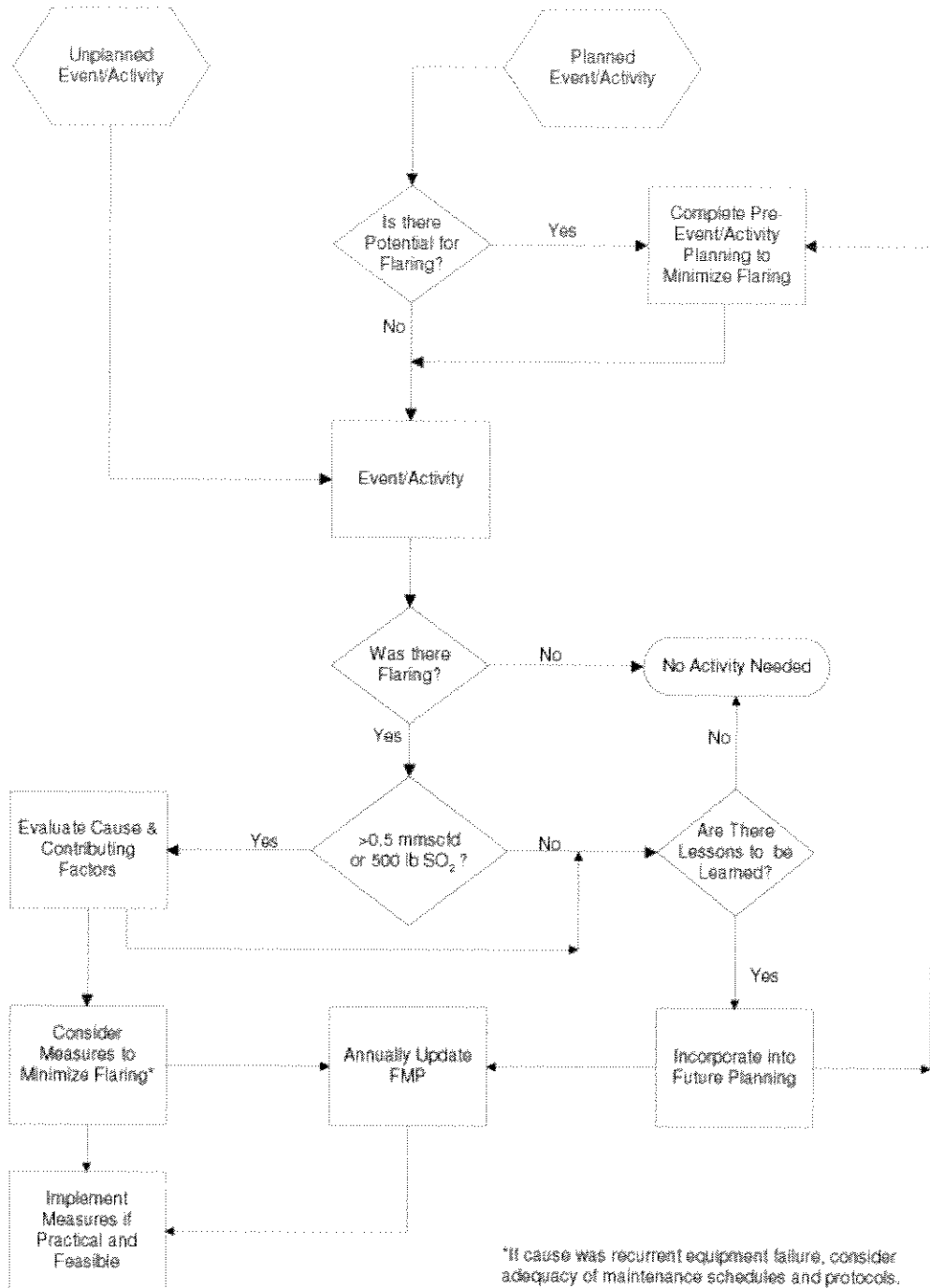
Some examples of these types of activities which are generally planned in advance and occur at varying frequencies include:

- routine maintenance activities which can have a weekly, monthly, or yearly frequency;
- reactor catalyst regeneration or change-out activities which can have a monthly, yearly, or multiple year frequency;
- major refinery turnarounds which have a frequency of every 5 to 6 years; and
- individual turnarounds at some process units which may have a different, more frequent schedule.

The Benicia Refinery has incorporated flare minimization procedures into the planning process for these events to ensure that previous experiences are considered, that the upcoming circumstances impacting the event are taken into account, and to see if any anticipated causes of flaring are identified. The planning process for activities identified as having the potential for flaring considers the following general questions:

- Can this activity result in a reportable level of flaring (greater than 0.5 mmscfd or 500 lb/day SO<sub>2</sub> emitted)?
- Has this event historically been a cause of a reportable flaring event?
- Why will this activity cause flaring? Can procedures be implemented to minimize or eliminate flaring?

**Figure 4**  
**Flare Minimization Flowchart**



\*If cause was recurrent equipment failure, consider adequacy of maintenance schedules and protocols.

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- Are there other events occurring at the same time, such as other units being out of service, which could impact the ability to recover fuel gas during this event? Can these events be staged and coordinated to maximize flare gas recovery and minimize the frequency and magnitude of flaring?
- What is the status of the refinery fuel gas balance? Can natural gas or other makeup fuels be backed out of the Fuel Gas Unit? Are COGEN and other large fuel gas consumers online to receive fuel gas?
- How is the refinery fuel gas balance expected to be managed during these events? Balance often changes significantly depending on what gas producers and consumers are impacted.
- Will the gases that are generated during depressuring, venting, purging, or other activities be of a quality that is acceptable for recovery?
- What mitigating activities should be incorporated in the activity plan to manage the potential flows to the Flare Gas Recovery System and/or the associated flares?

Any recommendations that are identified during this planning process are then considered for inclusion in the activity procedures and incorporated as appropriate.

#### **1.7.2 Flaring Event Review Program**

An important component of the flare minimization process is the review of flaring events that occur and exceed the BAAQMD levels for reportable flows (greater than 0.5 mmscfd or 500 lb/day SO<sub>2</sub> emitted). The flaring event review process is incorporated with the BAAQMD reporting requirements in the following manner:

- The occurrence of a reportable flaring event is identified;
- The event is managed to ensure the safety of facility operations, with the operations team considering both the maximization of the recovery of gases from the Flare Gas Header (depending on composition), and the minimization of any flared gases;
- All record keeping required by BAAQMD regulations is accomplished including flow recording, sampling of flared gases, and in the future monitoring of flare drum seal levels;
- These results are compiled to prepare a summary of the event quantities and flows; and
- An analysis is performed to identify the cause of the event.

The causal analysis involves a coordinated team of refinery operations, environmental, and staff from other disciplines as appropriate (e.g., mechanical and electrical). The team reviews the operational conditions and activities leading up to the flaring event, and upon determining a cause, identifies any

potential follow-up activities that may be implemented to minimize or eliminate the possibility of a similar event occurring.

Typical recommendations may include improvements to maintenance procedures, changes to operational practices, the addition of instrumentation to monitor critical parameters, and/or changes to the planning and execution of similar activities in the future to minimize the chance of a similar event.

### **1.7.3 Flare Minimization Through Reliability Improvement**

Over the years, the Benicia Refinery has instituted a series of management practices that have a direct and positive impact on the reliability of the equipment and processes in the refinery. These practices address such issues as equipment mechanical integrity, maintenance and inspection, training, and operating procedures. They generally can be organized along the lines of the Process Safety Management (PSM) rules under OSHA. The improved reliability has resulted in fewer unplanned equipment failures and greater unit run lengths (time between maintenance turnarounds).

Improved reliability reduces the amount of flaring in several ways. First, it reduces the number of unscheduled and emergency shutdowns. Such incidents generally result in significant flaring associated with the shutdown and subsequent startup activities and possibly flaring associated with clearing of the equipment that needs to be repaired. Reducing the number of such incidents obviously reduces the average amount of flaring done by the facility over time. Second, better reliability lengthens the average process unit run length. For example the average run length for the CKR back in the early 1980s was only about nine months, but with reliability improvements made over the years, the run length has been extended to almost three years. Clearly in the CKR example, better reliability has reduced planned startup/shutdown flaring (for the CKR) by a factor of three simply by reducing the number of downtimes needed for maintenance.

Individual reliability improvements may be difficult to quantitatively link to a flaring effect. However, in the example of the CKR, there were hundreds of changes made over the years that in aggregate improved the unit run length. Assigning a particular flaring reduction to a specific reliability improvement is at best problematic. Yet, the outcome of the reliability process is very clear. And for some units the effects are even more dramatic. Average run length for the FCCU in the early 1980s was about two years and now is approaching six years. However, when the FCCU is shutdown for turnaround, the entire refinery has to be shutdown with it. Clearly, improving FCCU reliability dramatically reduces the amount of flaring by more than just that associated with the FCCU.

In the years 2004 and 2005, with the assistance of a third party expert, Becht Engineering, the Benicia Refinery conducted a site-wide reliability assessment to identify opportunities for improvement in the reliability of equipment. A series of recommendations came out of that study that the refinery has already

implemented or is in the process of implementing. These study recommendations, as they relate to flare minimization, have been incorporated into this FMP.

### **1.8 Unique Factors at Benicia Refinery that Impact Flare Minimization**

To further understand the Flare Gas Recovery System and flare minimization procedures at the Benicia Refinery, it is important to appreciate that every refinery is different. Each is unique in its configuration, the environment in which it operates and the complexities of balancing the fuel gas, power, flare gas recovery and flaring systems with process operations. This is true for every refinery in the Bay Area, the United States, and throughout the world. Factors that differ significantly between refineries include:

- Refinery age and the historical development at the refinery site;
- Crude feedstocks that are processed;
- Size, capacity, and throughput of processing units;
- Reliability of electrical power systems;
- Processing configuration, complexity, and extent of upgrading capacity;
- Unit integration or ability of units to operate independently;
- Extent of investment by ownership over the years;
- Locally available resources (e.g., power, water, and land);
- Local regulatory climate; and
- Demand for different products within the local market.

When comparing the Benicia Refinery with other refineries the following features stand out as being unique:

- The Benicia Refinery is one of the newest refineries in the United States, built in 1969;
- With a nameplate capacity of 135,000 BPD, the Benicia Refinery is a small to medium sized modern refinery;
- The design focus of the Benicia Refinery is on upgrading crude oils to produce primarily gasoline and fuel products, with a high extent of upgrading/conversion (e.g., FCCU, CKR, and HCU) capacity;
- The Benicia Refinery is designed in a highly integrated fashion, which maximizes yield and energy efficiency, but can limit operational flexibility as all units are highly integrated with each other and the refinery as a whole operates as one entire system;
- The Benicia Refinery processes a wide variety of crudes, including purchased crude on the spot market that can affect operating parameters and yields;

- Operating within California and the Bay Area, the Benicia Refinery must comply with some of the most stringent environmental regulations governing all types of emissions to air, water, and land;
- The Benicia Refinery provides products to the California market, which requires special formulations including additional processing steps for product desulfurization and components to assist in clean fuel-burning; and
- Built in a compact manner, the Benicia Refinery has limited additional room for expansion.

From a technical perspective there are some additional features regarding the way the Benicia Refinery was designed and has evolved that specifically impact its fuel gas balance, flare gas recovery and flaring systems:

- To minimize the usage of water resources, the Benicia Refinery makes extensive use of air-cooled exchangers for condensing and cooling. This type of cooling minimizes the use of cooling water. However, during hot weather, the effectiveness of air coolers is reduced and consequently, the refinery produces significantly more fuel gas during hot weather.
- The COGEN was built in 2002 to produce both electrical power and steam. A significant benefit of COGEN is that it is a major consumer of refinery fuel gas which helps to maintain the balance between supply and consumption of fuel gas. Additionally, COGEN provides a third electrical power source for the refinery and reduces the likelihood of power failures (there are two power feeds from the PG&E grid). However, the COGEN requires frequent maintenance outages. As result, the shutdown of the COGEN can impact the fuel gas balance within the refinery. Also, the load at COGEN (e.g., fuel gas consumption) is dictated by the Benicia Refinery's electrical power demand because COGEN cannot be a net exporter of power to the PG&E grid. Additionally, the installation of COGEN added electrical switching equipment which has the potential for failure and malfunction.
- The composition of the refinery fuel must be carefully monitored and managed for safety, environmental (NO<sub>x</sub> control), and/or operability reasons. It is important not to route high nitrogen or hydrogen containing streams to the combustion sources (especially to the gas turbines).
- The refinery utilizes four gas turbines to drive compressors and blowers. These gas turbines increase fuel gas demand and improve the fuel gas balance. However, the gas turbines are sensitive to fuel gas quality and require blending of natural gas to maintain consistent quality.
- The Benicia Refinery processes its heaviest feed stocks in a fluid coker (CKR), whereas most refineries utilize delayed cokers for this process. A fluid coker has higher energy efficiency than a delayed coker. As a result, the fluid coker at the Benicia Refinery does not consume as much fuel gas as compared to a delayed coker.

This FMP has provided the above information to illustrate the significant extent of flare gas recovery that has already been achieved by the Benicia Refinery, and to highlight the refinery's unique characteristics, which will serve as a resource for later sections where facility limitations or reasons that flaring will continue to occur are further discussed, despite the refinery's best efforts to minimize the frequency and magnitude of flaring events.

### 1.9 Impact of Balancing Environmental Objectives on Flare Minimization

As has been discussed in previous sections, the Benicia Refinery was designed and is operated to achieve many desirable environmental objectives at the same time. Many of these objectives are interrelated, and improvements in one area often result in impacts in another. This is particularly true for the Flare Gas Recovery System and its associated flares. At the Benicia Refinery, substantial investments in equipment and operational changes have been made to direct previously uncaptured emissions to Flare Gas Recovery System. Some examples of these interrelated objectives are provided in Table 3, which highlights the relationship between effective implementation of various environmental objectives and the Flare Gas Recovery System.

It is important to note that for many of these objectives the Flare Gas Recovery System and associated flares have been consciously chosen as the destination of choice for these materials specifically because they achieve very significant acknowledged reductions in hydrocarbon emissions if flaring does occur.

**Table 3**  
**Impact of Balancing Environmental Objectives on Flare Minimization**

<b>Environmental Objective</b>	<b>Implementation Approach</b>	<b>Impact on Flare Gas Recovery System</b>
Highly integrated refinery design for yield and energy efficiency	Limited intermediate tankage (hot feeding between units), heat and process integration between units	The refinery essentially operates as one integrated unit; an upset in one unit can impact other units.
Design to minimize water usage	Extensive use of airfin coolers	Increased gas generation during hot weather requires significant refinery operational changes to minimize the frequency and magnitude of flaring events.
Minimization of NO <sub>x</sub> emissions	Installation of low NO <sub>x</sub> burners in furnaces and low NO <sub>x</sub> controls at gas turbines	Low NO <sub>x</sub> burners and technologies are less tolerant of low Btu content gases and can flame out more easily. Accordingly, it is more critical to prevent high nitrogen containing gases from entering the Flare Gas Recovery System.

**Table 3  
Impact of Balancing Environmental Objectives on Flare Minimization**

<b>Environmental Objective</b>	<b>Implementation Approach</b>	<b>Impact on Flare Gas Recovery System</b>
Capture emissions from rail car loading and unloading	Rail car unloading vapor recovery system	This system can produce surges in flow to the Flare Gas Recovery System. A program has been implemented to manage these surges, but this is still an ongoing operational challenge.
Limiting emissions from depressuring and opening process vessels (Regulation 8-10)	Direct vessel vents to Flare Gas Recovery System during depressuring and inerting process	Increased volume of gases to Flare Gas Recovery System primarily containing nitrogen, which has no heating value.
Improved energy efficiency of existing fired furnaces, boilers, or other gas users, which reduces emissions	Various efficiency improvement approaches including upgraded equipment design, burners, and controls	Improvements in efficiency reduce the net usage of fuel gas in the refinery, and move the fuel balance further towards an excess of gases.
Minimize air emissions from sewers and wastewater treatment plant (WWT)	Route hydrocarbons from maintenance activities to Flare Gas Recovery System instead of to the sewer or atmosphere	This increase in flow of these gases to Flare Gas Recovery System causes an increased loading on the Fuel Gas Unit.
Capture fugitive emissions from light hydrocarbon pump seals	Pump seals upgraded to tandem seals with seal pots routed to Flare Gas Recovery System	Increased base loading of gases to Flare Gas Recovery System.



## SECTION 2 TECHNICAL DATA

In accordance with Regulation 12-12-401.1, this section provides detailed descriptions and technical information for each applicable flare at the Benicia Refinery including upstream equipment and processes. During the drafting of this FMP, the Benicia Refinery met with the BAAQMD to review the adequacy of preliminary technical data. The technical data presented to the BAAQMD and additional data requested by the BAAQMD are presented in this section.

The Benicia Refinery operates the following “flare” systems:

- Refinery Flare Gas Recovery System including the South and North Flares
- Acid Gas Flare

This FMP does not address the Butane Flare, because this flare is exempt from the FMP requirements pursuant to Regulation 12-12-110.

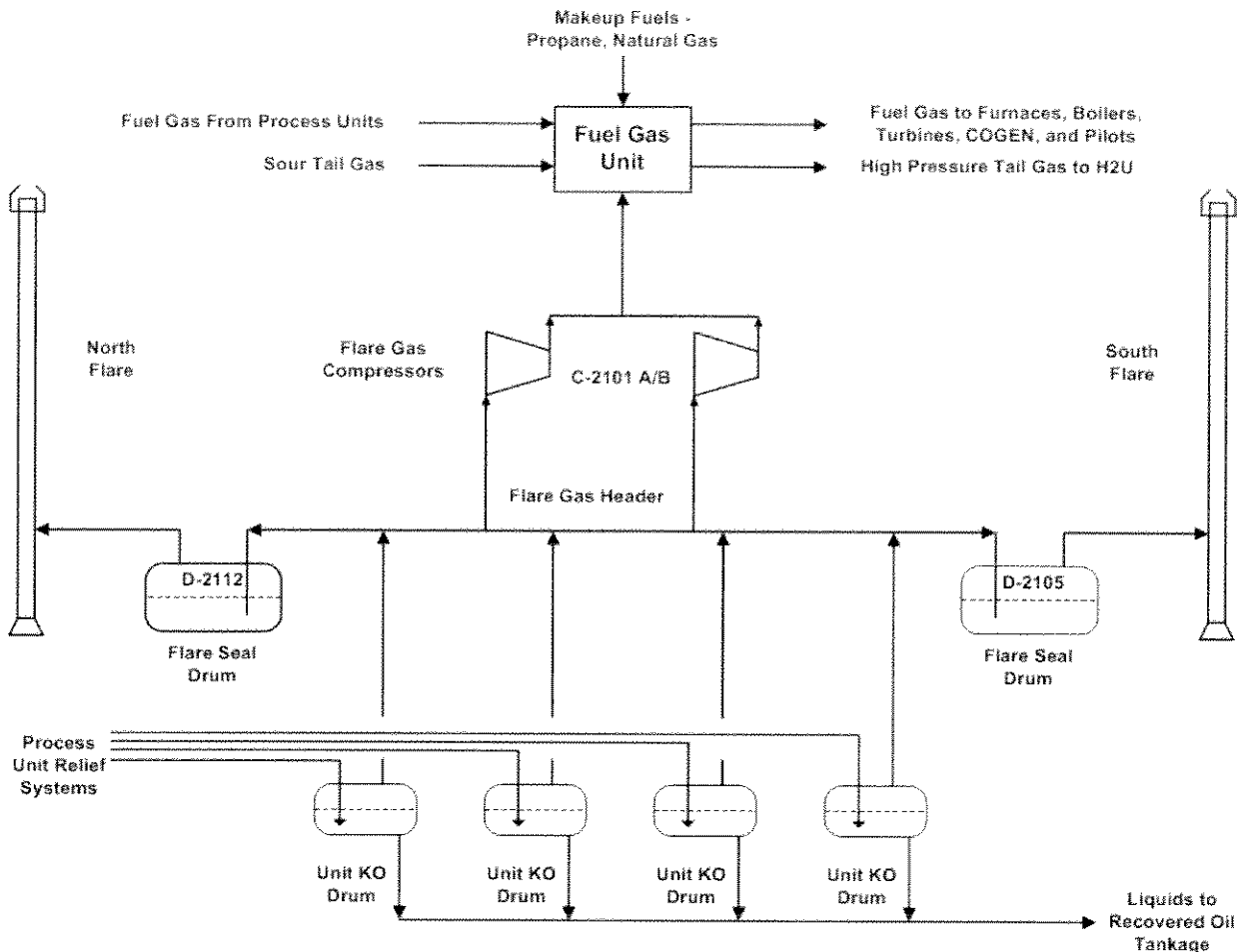
### 2.1 Refinery Flare Gas Recovery System

At the Benicia Refinery, the Flare Gas Recovery System is used to recover excess gases that are generated at various refinery processing units. These gases are collected in the Flare Gas Header and a majority (approximately 90 percent) are compressed and directed to the refinery Fuel Gas Unit. At the Fuel Gas Unit, the recovered gases are blended with other refinery sources of fuel gas, treated for removal of sulfur compounds, and directed to the refinery fuel gas users, including furnaces, boilers, gas turbines, and COGEN. The system can also direct gases to one or both of the flares that are connected to the Flare Gas Header. However, this occurs only if the composition of the gases is not compatible for reuse as fuel gas (e.g., nitrogen, steam, or low Btu content), or if the instantaneous rate of flow exceeds the capacity of the Flare Gas Compressors. By recovering these gases and reusing them, the refinery achieves multiple objectives – increased energy efficiency, reduced oil loss, minimization of the frequency and magnitude of flaring events, and effective control of hydrocarbon emissions.

The major components of the Flare Gas Recovery System include process unit liquid knock-out (KO) drums, the Flare Gas Header, Flare Gas Compressors, the Fuel Gas Unit (including fuel gas scrubbers and distribution headers), flare water seal drums, and the two flares (South and North). Figure 5 provides a simplified diagram of the Flare Gas Recovery System at the Benicia Refinery. A detailed process flow diagram of the Flare Gas Recovery System (Drawing No. 36-000-03E-73503) is provided in Appendix B.

The following provides a detailed description for each of the Flare Gas Recovery System components.

**Figure 5  
Flare Gas Recovery System**



### 2.1.1 Process Unit Liquid KO Drums and Flare Gas Header

Gases from process unit equipment pressure relief valves, and in some cases process vents, are collected in headers within the process units and routed to liquid knockout (KO) drums. The knockout drums capture and recover entrained liquids, and minimize the chance of liquid carry over into the Flare Gas Recovery System. Liquids collected in the process unit liquid KO drums are pumped to recovered oil tankage, and are then reprocessed as feed stock to various process units. The vapors from the knockout drums enter the Flare Gas Header.

The Benicia Refinery Flare Gas Recovery System includes the following process unit liquid KO drums:

- D-2101 is located at the FCCU and serves the FCCU, CLE, PS, VLE, NRU, ALKY, and CKR units.

- D-2102 is located at the H2U and serves the H2U, HCU and COGEN units.
- D-2113 is located at the H2U and serves the CFHU, FG, DIM, SGU, COGEN and H2U units.
- D-2103 and D-2104 are located at the ALKY and serve the ALKY and UTIL units.
- D-2131 is located at ALKY and serves the ALKY.
- D-2130 is located at the MRU and serves the MRU and ULSD units.

There are additional tie-ins to the Flare Gas Header that are not routed through a process unit liquid KO drum. These tie-ins include various vapor recovery systems, product spheres, and the Acid Gas Flare system (via D-2107, the SGU Liquid KO Drum) which is normally closed.

The Flare Gas Header is a 42-inch line that runs throughout the refinery. This header is used to connect the process unit KO drums to two Flare Gas Compressors. A flare seal drum and a flare are also connected to both the south and north ends of the Flare Gas Header. One or more of the two compressors are used to recover gases from the Flare Gas Header and send them to the Fuel Gas Unit where they are treated to produce fuel gas for furnaces, boilers, gas turbines, and COGEN. Under normal operating conditions, the Flare Gas Compressors remove enough gases in the Flare Gas Header to maintain a header pressure that does not "break" the water seal in the flare water seal drums. Under normal operating conditions, the south and north water seals prevent gases from reaching the flares and ensure that all the gases in the Flare Gas Header are compressed and sent to the refinery's Fuel Gas Unit.

Detailed piping and instrumentation diagrams of the process unit liquid KO drums (Drawing Nos. 112-KE-31, 114-KE-9, 116-KE-12, 43-000-03D-17468 and 44-000-03D-30869) are provided in Appendix C.

### **2.1.2 Flare Gas Compressors, C-2101 A/B**

The Flare Gas Recovery System utilizes two Flare Gas Compressors (C-2101 A/B) to route gases in the Flare Gas Header to the Fuel Gas Unit via the Sour Gas Header. C-2101 A is a 3-stage compressor that was installed in 1975 (this unit was originally constructed in 1953 and was installed as a used unit). C-2101 B is a 2-stage compressor that was installed as a new unit in 1983. These two reciprocating compressors are each rated at 6 mmscfd. This rating is based on inlet conditions of 0 psig and 80 °F for C-2101 A and 0 psig and 70 °F for C-2101 B. Both of the Flare Gas Compressors discharge to the Sour Gas Header at 87 psig at 100 °F. When C-2101 A was originally installed it was designed to discharge to either the Sour Gas Header or to the higher pressure CLE, however, the line-up to CLE is not currently used.

Prior to 1975, all gases sent to the Flare Gas Header were flared, which was a common operating practice (and still is at many refineries throughout the world).

The first Flare Gas Compressor (C-2101 A) was installed in 1975 when it was very uncommon for refineries to operate flare recovery systems. The Benicia Refinery operated for eight years with a single Flare Gas Compressor. During this eight-year period, flaring occurred whenever the Flare Gas Compressor was down for maintenance. Additionally, if there was a mechanical failure, the Flare Gas Compressor could be down for a prolonged period of time to conduct repairs. In 1983, a second Flare Gas Compressor (C-2101 B) was installed which greatly improved the on-line availability and significantly reduced flaring.

Today, during normal operations, one Flare Gas Compressor is operated as the primary unit and the other is available as a spare unit. Primary and spare duties are switched when the off-line compressor is started and the on-line compressor is shut down. When maintenance is not being conducted at the off-line compressor, it is maintained in hot standby (warm jacket water, oil circulating, suction and discharge valves unblocked) so that it can be quickly brought into service if needed. This mode of operation has been selected because it achieves the primary goal of having at least one Flare Gas Compressor on-line. This can be virtually achieved if there is always a spare Flare Gas Compressor that is available. However, the spare unit cannot always be available because inspection, maintenance, and repairs must be conducted. As a result, it is still possible that both Flare Gas Compressors may not be available during these times. The use of a primary and spare has greatly improved on-line reliability and it is very uncommon that at least one Flare Gas Compressor is not available.

Operating the spare Flare Gas Compressor in constant service would approximately double the amount of time needed for inspection, maintenance, and repair. During inspection, maintenance, or repair of one compressor, there is not spare unit available if the on-line compressor experiences a failure. Therefore, if a failure of the on-line compressor occurs during inspection, maintenance, or repair of the off-line compressor, flaring would occur for days or weeks until one of the two compressors could be put back into service. Any reductions in flaring achieved by running the spare compressor in constant service would be very small and significantly less than the increased flaring that would be caused by losing both compressors. Flaring reductions would only occur by eliminating the 10 to 20 minute period that it takes to bring the off-line compressor into service when there has been a failure of the on-line compressor. There would be no reduction in flaring during planned switching of the compressors because the off-line unit is started before shutting down the on-line unit.

It is possible to operate both Flare Gas Compressors simultaneously. However, under normal operating conditions, a single Flare Gas Compressor provides more than enough capacity to recover all the gases sent to the Flare Gas Header. If a larger than normal load on the Flare Gas Header is expected (e.g., planned maintenance) and enough fuel gas users are anticipated to consume fuel gas (e.g., natural gas can be cut to the Fuel Gas Unit), refinery operators can proactively start-up the spare Flare Gas Compressor (assuming that it is

available). Proactively using both Flare Gas Compressors reduces flaring. However, it is not common for situations to occur when both units can be used to reduce flaring. Continuous operation of both Flare Gas Compressors would actually increase flaring because it would decrease on-line reliability (there would be a greater chance that both could be down at the same time).

Major maintenance of the Flare Gas Compressors is not scheduled and there are no manufacturer's recommendations for major maintenance. Flare Gas Compressor operating parameters are closely tracked. If there are indications that performance is beginning to degrade (e.g., increase in operating temperature or a decrease in compression capacity), the spare Flare Gas Compressor is first placed on-line as the new primary unit. After the spare Flare Gas Compressor is placed on-line, the original unit is taken off-line to conduct maintenance and repair. Once the maintenance and repair activities have been completed, that unit becomes available as the spare unit and is placed in hot standby. Minor maintenance activities such as lubrication are conducted at regular intervals.

Additionally, the Benicia Refinery has recently implemented a program of conducting an approximate 14-day major and an approximate 5-day minor inspection of each compressor approximately every 8 and 3 years, respectively. However, the inspection schedule is adjusted if major maintenance occurs based on tracking compressor performance (described above). At the time of the major and minor inspections, maintenance and repair is conducted based on the results of the inspection and can add to the time that the unit is down (not available as a standby unit).

There are no logic controls that would automatically trigger the spare Flare Gas Compressor to come on-line if the primary unit were to fail and go off-line. The spare compressor must be manually started. However, during a planned switch of the primary and spare compressor, the spare is always placed into service prior to removing the primary from service. In the event that the primary Flare Gas Compressor experiences a mechanical failure and goes off-line unexpectedly, the spare unit is started as soon as possible to minimize flaring. It typically takes approximately 10 to 20 minutes for an operator to be called out and complete the start-up sequence. During the period of time that there are no Flare Gas Compressors in service, all gases collected in the Flare Gas Header must be flared because there is no path to the Fuel Gas Unit.

The Flare Gas Compressors are equipped with a number of automatic shutdown controls to prevent mechanical failure. For example, both Flare Gas Compressors have a high temperature trip that is set at the maximum operating discharge temperature of 325° F. The Flare Gas Compressors are also equipped with automatic shutdown controls for high oxygen (set at 4 percent oxygen) to prevent a combustible mixture at the down stream Fuel Gas Unit. A number of issues can lead to high operating temperatures such as a problem with the lubrication and cooling systems. Higher than normal operating

temperatures can also be a sign of excessive wear or other mechanical problem that require maintenance. If low molecular weight gases, such as hydrogen, are sent to the Flare Gas Compressors, operating temperature can potentially increase up to the high temperature trip point. High oxygen levels can be caused by air leaks into the Flare Gas Header. Flare Gas Compressor trip points are summarized in Table 4. It is extremely uncommon that the Flare Gas Compressors shutdown because of high temperature, high oxygen, or some other automatic trip. During a trip event, all gases sent to the Flare Gas Header would be sent to the South and North Flares. After a trip event, the spare Flare Gas Compressor, if available, would be started as soon as possible, normally in about 10 to 20 minutes.

There are instances when the Flare Gas Compressor(s) must be manually shutdown, which will result in flaring. High levels of nitrogen cannot be sent to the Fuel Gas Unit because some combustion equipment are sensitive to large changes in fuel heating value (Btu content). Nitrogen reduces the fuel's heating value which can impact operations and NO<sub>x</sub> control at the gas turbines and at COGEN. The gas turbines are particularly sensitive to fuel heating value. A big enough drop in heating value caused by sending too much nitrogen to the fuel gas system can cause a gas turbine to trip off-line. Such an event would cause significant flaring because loss of a gas turbine would cause an emergency shutdown of one or more refinery process units (both the unplanned shutdown and subsequent startup would cause flaring). If large levels of nitrogen are expected from operations such as vessel depressurization, equipment cooling, and equipment warming, operators will shutdown the Flare Gas Compressors and then restart them when nitrogen levels have dropped.

**Table 4**  
**Flare Gas Compressor Trip Set Points**

Operating Parameter	Trip Set Point	
	C-2101 A	C-2101 B
Compressor discharge high temperature, °F	325	325
Compressor suction high temperature, °F	140	140
Compressor bearing high temperature, °F	none	210
Cooling water high temperature, °F (1 <sup>st</sup> /2 <sup>nd</sup> stage)	none	130/140
High oxygen, percent	4	4
Lube oil low pressure, psi	20	15
Compressor suction low pressure, inches of H <sub>2</sub> O	0	0
Piston rod overload, delta psi (1 <sup>st</sup> /2 <sup>nd</sup> stage)	none	35/100
D-2114 high level, inches	157	none
D-2115 high level, inches	33	none
D-2116 high level, inches	85	none
D-2117 high level, inches	126	none
D-2119 high level, inches	none	72
D-2120 high level, inches	none	57
D-2121 high level, inches	none	99

Detailed piping and instrumentation diagrams of the two Flare Gas Compressors (Drawing Nos. 36-000-03E-03537, 36-000-03E-09060 and 36-000-03E-09061) are provided in Appendix C.

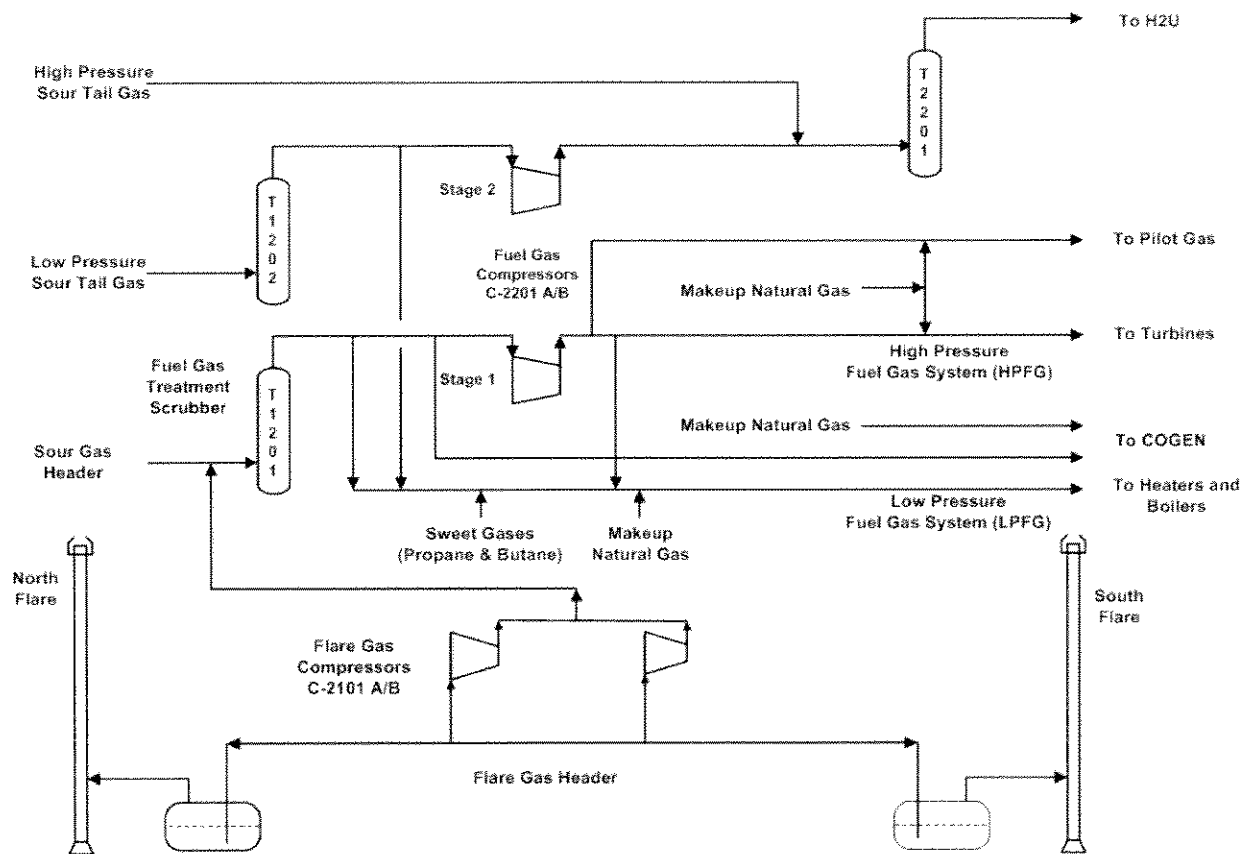
### 2.1.3 Fuel Gas Unit

The Flare Gas Compressors are used to send an average of about 4 to 5 mmscfd of gas from the Flare Gas Header to the Fuel Gas Unit. In the Fuel Gas Unit, these recovered gases are blended with other refinery gases and, at times, purchased natural gas to produce an average of about 75 mmscfd of fuel gas that is burned in refinery furnaces, boilers, gas turbines, and COGEN. In addition, the Fuel Gas Unit produces an average of about 23 mmscfd of hydrogen rich gases that are sent to the H2U. The following gas streams are produced at the Fuel Gas Unit:

- Low pressure fuel gas (LPFG) for furnaces and boilers;
- High pressure fuel gas (HPFG) for four process gas turbines located at ALKY, HCU, FCCU, and CLE;
- Pilot gas;
- A blend of refinery fuel gas and natural gas for the COGEN; and
- High pressure tail gas (HPTG) for the H2U.

The recovered gases (an average of about 4 to 5 mmscfd) are sent to the sour gas header and mixed with other gases which are sent to a Fuel Gas Treatment Scrubber (T-1201) to produce an average of about 50 mmscfd of clean refinery fuel gas. This scrubbed refinery fuel gas from T-1201 is then sent along with other gases and/or purchased natural gas to the LPFG system, HPFG system, and the COGEN fuel system. The scrubbed refinery fuel gas from T-1201 can also be sent to the pilot gas system which is normally supplied only with purchased natural gas. Figure 6 provides a simplified diagram of the Fuel Gas Unit.

**Figure 6  
Fuel Gas Unit**





### 2.1.3.1 Fuel Gas Treatment Scrubber, T-1201

The Fuel Gas Treatment Scrubber is an amine treater, which contacts a circulating amine solution with sour fuel gases in a packed bed. In the scrubber, sulfur compounds consisting primarily hydrogen sulfide ( $H_2S$ ) are absorbed from the sour fuel gas into the amine solution. This fuel gas treatment is required to remove the sulfur compounds so they do not form  $SO_2$  when the fuel gas is ultimately combusted in refinery furnaces, boilers, gas turbines, and COGEN. The circulating amine solution is then regenerated in a stripper with a steam reboiler and returned to the scrubber. The  $H_2S$  rich gases from the stripper are routed to the SGU where elemental sulfur is ultimately recovered and sold as a product. The refinery operates additional fuel gas treaters which share a common amine regeneration system.

The Fuel Gas Treatment Scrubber (T-1201) has a maximum capacity of about 70 mmscfd of sour fuel gas. The clean fuel gas produced at T-1201 is regularly sent to the HPFG system, LPFG system, and COGEN fuel system. Additionally, the clean fuel gas can be sent to the pilot gas system. Light hydrocarbons (primarily methane and ethane) from CLE are the primary source of sour fuel gas that feeds T-1201. CLE supplies on average about 36 mmscfd of sour fuel gas to T-1201 which accounts for about 70 percent of the total sour fuel gas sent to T-1201. The gases at CLE are originally generated at the FCCU and CKR and are sent to CLE to produce pentanes and various intermediate feed products for ALKY, DIM, LCHFF, and HCNHF. The gases from CLE that are sent to T-1201 (about 36 mmscfd) account for a small percentage of the total gases processed at CLE.

There are a number of other smaller sour fuel gas streams that makeup the remainder of the sour fuel gas feed to T-1201 (the remaining 30 percent not supplied by CLE). The Flare Gas Compressors supply on average about 4 to 5 mmscfd of sour fuel gas to T-1201 which accounts for about 10 percent of the total sour fuel gas sent to T-1201. A majority of this remaining T-1201 feed comes from VLE which is primarily supplied by the PS and HCU.

A detailed piping and instrumentation diagram that includes the Fuel Gas Treatment Scrubber (Drawing No. 122-KE-2) is provided in Appendix C.

### 2.1.3.2 HPFG System

The HPFG system supplies an average of about 12 mmscfd of fuel gas at about 215 psig to the four gas turbines. HPFG is mostly comprised of refinery fuel gas that has been scrubbed in T-1201, which is then raised to a higher pressure by reciprocating compressors (C-2201 A/B, Stage 1). It is important that the heating value of HPFG is maintained between about 950 and 1100 Btu/scf because the gas turbines are sensitive to the heating value of fuel gas. On average, less than 1 mmscfd of purchased

natural gas is blended into HPPFG. Excess HPPFG (compressed and scrubbed refinery fuel gas from T-1201 and C-2201 A/B, Stage 1) is sent to the LPFG system.

### **2.1.3.3 LPFG System**

The LPFG system supplies an average of about 53 mmscfd of fuel gas at about 60 psig to the refinery. LPFG is used on a continuous basis at the furnaces and boilers throughout the refinery. In addition, LPFG is used for auxiliary startup burners at the FCCU and CKR and for a startup furnace at ALKY.

LPFG is primarily comprised of refinery fuel gas that is scrubbed at T-1201. LPFG also includes excess HPPFG (compressed and scrubbed refinery fuel gas from T-1201 and C-2201 A/B, Stage 1) that is let down into the LPFG system. In addition, LPFG also includes excess hydrogen-rich tail gas from the HPTG system that is scrubbed at T-1202 (an average of about 8 mmscfd). Additionally, sweet refinery fuel gas (propane and butane) can be sent to the LPFG system (an average of less than 1 mmscfd). When there is insufficient refinery fuel gas available, natural gas is purchased and added to the LPFG system. An average of about 9 mmscfd of purchased natural gas is used for the LPFG system. Most of the purchased natural gas is used during the cool winter months and very little is used during the warm summer months.

If excess LPFG is produced, it is sent to the Flare Gas Header. This situation is referred to as being "long on fuel gas" and typically occurs during the warm summer months and when fuel gas consumers (e.g., furnaces, boilers, gas turbines, and COGEN) are out of service. On average, about 0.1 mmscfd of LPFG is sent back to the Flare Gas Header. Flaring can result if too much LPFG is sent back to the Flare Gas Header. To minimize the frequency and magnitude of flaring when the refinery is long on fuel gas, the use of purchased natural gas is minimized and a variety of efforts are made (such as unit adjustments and production cuts) to minimize the production of the various sources of refinery fuel gas. These flare minimization efforts are discussed in more detail in subsequent sections of this FMP.

### **2.1.3.4 COGEN Fuel System**

An average of about 10 mmscfd of fuel gas at about 60 psig (further compressed at the COGEN) is supplied to the COGEN to fuel both the gas turbine and heat recovery steam generator (with auxiliary firing). The fuel sent to the COGEN is comprised of refinery fuel gas that has been scrubbed in T-1201. Additionally, purchased natural gas is sent to COGEN. Both fuels must be precisely blended to ensure compliance with strict BAAQMD emission limits. On average, the total fuel sent to COGEN is about 7 mmscfd of refinery fuel gas and 3 mmscfd of purchased natural gas.

### **2.1.3.5 Pilot Gas System**

The pilot gas system supplies fuel to pilots throughout the refinery including boilers, furnaces, and the flares. On average, less than 1 mmscfd of fuel gas at about 30 psig is needed for the pilot gas system. Typically, purchased natural gas is used to supply the pilot gas system. However, refinery fuel gas that is scrubbed in T-1201 and compressed at C-2201 A/B, Stage 1 can also be used to supply pilot gas system.

### **2.1.3.6 HPTG System**

The HPTG system is used to recycle hydrogen-rich streams from hydrofiners and the HCU back to the H2U as a feedstock to efficiently produce hydrogen. The HPTG system scrubs and compresses tail gas streams containing approximately 75 percent hydrogen to produce treated HPTG for the H2U. This system produces an average of about 23 mmscfd of HPTG. The HPTG system utilizes two treatment scrubbers (T-1202 and T-2201) that are similar in design and operation to T-1201. Feed streams to the HPTG system include both high and low pressure sour tail gas. A reciprocating compressor (C-2201 A/B, Stage 2) is used to compress the LPTG after scrubbing. The volume of HPTG sent to H2U reduces the amount of natural gas required to manufacture hydrogen.

When the supply of HPTG is greater than can be recycled to the H2U, a portion of the gas must be sent to the LPFG system. On average, about 8 mmscfd of scrubbed HPTG from T-1202 is let down into the LPFG system.

### **2.1.4 Flare Water Seal Drums, D-2105 and D-2112**

The Flare Gas Recovery System at the Benicia Refinery utilizes two flare water seal drums, one located at the South Flare (D-2105) and one located at the North Flare (D-2112). The flare water seal drums serve two primary purposes; (1) to create a water seal for the Flare Gas Header which prevents gases from flowing to the flares during normal operating conditions and (2) to minimize the carry over of hydrocarbon liquid into the flares in the event that gases are sent to the flares. Liquids from the flare water seal drums are pumped to the sour water tank (TK-2801).

The South Flare water seal drum is equipped with 1-inch notched internal overflow weir to maintain a constant level for the water seal equal to the weir height. At the North Flare water seal drum, a constant water level is maintained using a 6-inch drain line that sends flow around an internal wall. The Flare Gas Header enters through the top of each flare water seal drum and extends into the water. The submerged end of the Flare Gas Header creates a positive barrier or "water seal" that prevents gases in the header from reaching the flare under normal operating conditions. To maintain a water seal, water is continuously supplied to the flare water seal drums. The water flow rate is controlled by restriction orifices. Stripped sour water is the primary water source with fire water used as a backup supply. The fire water backup is activated by a low

pressure controller. Steam is also provided to D-2105 and D-2112 to keep the liquid warm.

Each flare water seal drum is equipped with a 24-inch diameter horizontal “H” sparger with approximately 8,000 ½-inch holes that allow for uniform distribution of gases beneath the water. Additionally, each flare water seal drum is equipped with an 8-inch diameter auxiliary sparger also with ½-inch holes. The auxiliary sparger in the North Flare water seal drum is normally closed. Table 5, provides the water seal heights for each flare water seal drum. If the pressure in the Flare Gas Header rises above normal operating conditions, the 16-inch water seal in the South Flare water seal drum will be the first to “break” and gases will be sent to the South Flare. If the header pressure is great enough to break “H” sparger water seals, then gases will be sent to both the South and North Flares.

**Table 5  
Flare Water Seals**

Flare Water Seal Drum	Water Seal, inches	
	“H” Sparger	Auxiliary Sparger
South (D-2105)	31	16
North (D-2112)	27	Sparger normally closed <sup>(1)</sup>

<sup>(1)</sup>If the sparger is opened, the water seal would be 13 inches.

For both the South and North Flares, two 36-inch diameter lines connect the head space of each flare water seal drum to its respective flare.

Detailed piping and instrumentation diagrams that include the flare water seal drums (Drawing Nos. 136-KE-7 and 136-KE-8 for the South and North Flares, respectively) are provided in Appendix C.

### 2.1.5 Flares, South and North

The South and North Flares (including their associated water seal drums) were installed in 1969 and 1975, respectively. Both the South and North Flare stacks consist of 48-inch diameter pipes which are 345 feet tall (the flare tips are 10 feet, so the total flare height is 355 feet). Two 36-inch diameter lines connect each flare water seal drum to its flare stack. Gases are burned at the flare tips which are a smokeless, steam-assisted design by John Zink. The design capacity of the South and North Flares is 1.2 million lb/hr each.

To maintain smokeless combustion, steam is passed through eductor jets to aspirate air into the base of the flame. Additionally, at each flare, steam can be sent to external jets on the corona of the flare tip to help control the flame shape and cool the tip. At each flare, approximately 70,000 lb/hr of steam at a pressure of 125 psig can be supplied to the flare eductors and external jets. During flare events, flare operators adjust the steam rate from the Refinery Control Center to promote cleaner burning (smokeless) operation. Video monitors in the Refinery Control Center allow operators to observe flame characteristics and adjust steam rates accordingly. Smokeless combustion can

be maintained at gas flow rates of about 100,000 to 140,000 lb/hr to each flare tip.

Each flare is equipped with four pilots that burn constantly to ignite any sudden release of gas to the flares. A constant supply of about 1.4 MMBtu/hr of pilot gas (refinery fuel gas and/or natural gas) is maintained at each flare. Temperature sensors at each pilot check for continuous operations. If there is a pilot failure, a trouble alarm is sounded at the Refinery Control Center and the pilots are ignited from the ground by a flame propagation system. Purge gas (or sweep gas) is not sent to the South or North Flares. However, "center" steam is used as a sweep at both the South and North flare. There is a natural gas purge line to the North Flare, but this line is blocked in and blinded.

Detailed piping and instrumentation diagrams that include the South and North Flares (Drawing Nos. 136-KE-7 and 136-KE-8 for the South and North Flares, respectively) are provided in Appendix C. A detailed process and instrumentation diagram that includes the flare pilot igniter for the South Flare (Drawing No. 136-KD-7C) is provided in Appendix C. The flare pilot igniter for the North Flare is shown on the North Flare piping and instrumentation diagram listed above (Drawing No. 136-KE-8).

## **2.2 Acid Gas Flare System**

The Benicia Refinery operates an Acid Gas Flare which was installed in 1969 when the refinery was constructed. The Acid Gas Flare is designed to ensure effective destruction of primarily hydrogen sulfide and ammonia in relief vents that come from potentially sulfur containing streams located in the SGU. These vent streams from the SGU contain little or no hydrocarbons. These gas sources are not continuous and only rarely require venting; there were no events of a reportable quantity (greater than 0.5 mmscfd) in 2005. The Acid Gas Flare presents two advantages by segregating higher sulfur gases from other recovered fuel gases – first, the higher sulfur sources can cause significant corrosion and require special materials of construction, and second, by segregating these sources any events that occur with high sulfur streams can be immediately recognized and addressed.

The major components of the Acid Gas Flare system include the SGU liquid KO drum, acid gas flare line, Acid Gas Flare water seal drum, liquid accumulator drum, and Acid Gas Flare. The Acid Gas Flare system does not use a compressor to recover acid gas because the flows are infrequent, of a low volume, and of high sulfur content that is not a good candidate for reuse as fuel gas. A detailed process flow diagram of the Acid Gas Flare (Drawing No. 36-000-03E-73504) is provided in Appendix B.

### **2.2.1 SGU Liquid KO Drum, D-2107 and Acid Gas Flare Line**

The SGU relief system is routed to a liquid KO drum (D-2107) located at the SGU. Acid gas from D-2107 is sent via the acid gas flare line to the Acid Gas Flare water seal drum and then to the Acid Gas Flare. The SGU liquid KO drum minimizes the chance of liquid carry over into the acid gas flare system. Liquid

collected in the D-2107 is pumped via enclosed piping to the sour water tank, TK-2801.

The acid gas flare line is a 16-inch diameter line originating at the SGU liquid KO drum and terminating at the Acid Gas Flare water seal drum located near the Acid Gas Flare. There is an additional tie-in to the Acid Gas Flare line that is not routed through the SGU liquid KO drum. This tie-in is used to route HPTG from the PS and VLE to the Acid Gas Flare during emergency events.

A detailed piping and instrumentation diagram of the SGU Liquid KO Drum (Drawing No. 117-KE-4B) is provided in Appendix C.

### **2.2.2 Acid Gas Flare Water Seal Drum, D-2106 & Liquid Accumulator Drum, D-2108**

The Acid Gas Flare System utilizes a water seal drum (D-2106) that serves two primary purposes; (1) to create a water seal for the acid gas header which prevents gases from flowing to the flares during normal operating conditions and (2) to minimize the carry over of hydrocarbon liquid into the flare in the event that gases are sent to the flare. Acid gas from D-2106 is sent to the acid gas flare. Liquids from D-2106 flow by gravity to the liquid accumulator drum (D-2808) where it is pumped to the sour water tank (TK-2801).

The Acid Gas Flare line enters through the top of the water seal drum and extends vertically into the water (dip leg) creating a 16-inch diameter opening 6 inches below the water surface. The submerged end of the Acid Gas Flare line creates a positive barrier or "water seal" that prevents gases in the header from reaching the Acid Gas Flare under normal operating conditions. The height of the water seal is established using a drain line that creates a 6-inch water level above the acid gas dip leg opening. To maintain a water seal, water is continuously supplied to the water seal drum. The water inlet flow rate is controlled by a restriction orifice. Stripped sour water is the primary water source with fire water used as a backup supply. The fire water backup is activated by a low pressure controller. Steam is also provided to D-2106 to keep the liquid warm.

A single 16-inch diameter line connects the head space of the Acid Gas Flare water seal drum to the Acid Gas Flare.

Overflow liquids from the Acid Gas Flare seal drum (D-2106) flow by gravity to the liquid accumulator drum (D-2108) from which they are pumped to the sour water tank (TK-2801). A balance line from the top of D-2106 is connected to the top of D-2108 to equalize pressure in the two drums. A level controller at D-2108 activates the pump to the sour water tank (TK-2801).

A detailed piping and instrumentation diagram that includes the Acid Gas Flare water seal drum and liquid accumulator drum (Drawing No. 136-KE-7) is provided in Appendix C.

### **2.2.3 Acid Gas Flare**

The Acid Gas Flare tip is located adjacent to the South Flare tip on the South Flare stack. A 16-inch diameter line connects the water seal drum to the Acid Gas Flare. Gases are burned at the flare tips which are a smokeless, steam-assisted design by John Zink. The design capacity of the Acid Gas Flare is 79,000 lb/hr including both purge gas and combustion assist gas. Steam is utilized at the Acid Gas Flare tip to minimize flare pluming. During flaring events, the steam rate is automatically adjusted to maintain a specific acid gas to steam ratio. Video monitors in the Refinery Control Center allow operators to observe flame characteristics.

The Acid Gas Flare is equipped with three pilots that burn constantly to ignite any sudden releases of gases to the flares. A constant supply of about 0.35 MMBtu/hr of pilot gas (refinery fuel gas and/or natural gas) is maintained at the flare. Temperature sensors at each pilot check for continuous operations. If there is a pilot failure, a trouble alarm is sounded at the Refinery Control Center and the pilots are ignited from the ground by a flame propagation system.

Combustion assist gas (fuel gas) is typically added to the acid gas (at the acid gas water seal drum) at a rate of up to about 3.1 mmscfd to improve flare combustion during a flaring event. The addition of combustion assist gas is controlled by computer program to add fuel gas when a release is detected, either by the flow meter or if indicated by the valve position of sources routed to the flare. Additionally, the Acid Gas Flare utilizes a continuous flow purge gas (natural gas) to mitigate pulsation in the flare. A constant supply of about 0.05 mmscfd of purge gas is added to the 16-inch diameter line that connects the water seal drum (D-2106) to the Acid Gas Flare.

A detailed piping and instrumentation diagram that includes the Acid Gas Flare (Drawing No. 136-KE-7) is provided in Appendix C. A detailed piping and instrumentation diagram that includes the flare pilot igniter for the Acid Gas Flare (Drawing No. 136-KD-7C) is provided in Appendix C.

## **2.3 Monitoring Equipment**

The Benicia Refinery operates flare monitoring and control equipment to ensure proper operation of the flare systems. This section provides detailed information regarding the various monitoring and control equipment.

### **2.3.1 Flare Volumetric Flow Rate Monitoring**

In accordance with Regulation 12-11-501, the Benicia Refinery installed Panametrics ultrasonic volumetric flow meters in November 2003 at the South, North, and Acid Gas Flares. For the South and North Flares, the flow meters are installed in the 42-inch diameter (41.5-inch ID) Flare Gas Header approximately 50 and 450 feet upstream of the South and North Flare water seal drums, respectively. The South and North flow meters have a range of about 0.4 to 230 mmscfd. For the Acid Gas Flare, the flow meter is installed in the 16-inch diameter (15.25-inch ID) Acid Gas Flare line approximately 50 feet upstream of

the Acid Gas Flare water seal drum. The acid gas flow meter has a range of about 0.06 to 30 mmscfd. Each flow meter meets the following specifications:

- The minimum detectable velocity is 0.1 foot per second;
- Continuously measures the range of flow rates corresponding to velocities from 0.5 to 275 feet per second in the header;
- Manufacture's specified accuracy of +/-5 percent over the range of 1 to 275 feet per second;
- Each meter is installed where the measured volumetric flow is representative of flow to the flare it monitors;
- Access is provided for the BAAQMD to verify proper installation and operation; and
- Each meter is maintained to be accurate to within +/- 20 percent as demonstrated by flow verification conducted every 6 months in accordance with Regulation 12-11-402.

Volumetric flow rate data for the flares are continuously recorded in the refinery's data historian. The data historian tag numbers for the volumetric flow rate (raw data) from South, North, and Acid Gas Flares are 21F252, 21F253, and 21F254, respectively.

The raw data for the South and North Flares are "validated" based on the Flare Gas Header pressure. When the header pressure is below the level needed to break the water seal in the respective seal drum, it is assumed that there is no flow to the South or North Flares. This "validation" is needed because under "no-flow" conditions, the meters often record a small flow rate due to noise. The data historian tag numbers for the "validated" data are 21F252A, 21F253A for the South and North Flares, respectively. The data historian tag number for the Flare Gas Header Pressure is 21P035.

Under normal operations for the South Flare, the auxiliary sparger is un-blocked and the raw flow values are corrected to zero flow when the header pressure is less than 12 inches of water column (16 inches of water column is needed to break the water seal as shown in Table 5). However, if the auxiliary sparger is blocked-in at the South Flare, the raw flow values are corrected to zero flow if the header pressure is less than 24 inches of water column (31 inches of water column is needed to break the water seal as shown in Table 5).

Under normal operations for the North Flare, the auxiliary sparger is blocked-in and the raw flow values are corrected to zero flow when the header pressure is less than 24 inches of water column (27 inches of water column is needed to break the water seal, as shown in Table 5). However, if the auxiliary sparger is un-blocked at the North Flare, the raw flow values are corrected to zero flow if the header pressure is less than 12 inches of water column (13 inches of water column is needed to break the water seal, as shown in Table 5).



Detailed piping and instrumentation diagrams of the ultrasonic flow meters (Drawing Nos. 131-KE-19D, 131-KE-19E, and 131-KE-21B) are provided in Appendix C.

**2.3.2 Pilot and Purge Gas Monitoring**

In accordance with Regulation 12-11-504, the volumetric flow rate of pilot and purge gases must be (1) continuously monitored or (2) other information must be monitored so that it may be used to calculate the flow rate. The volumetric flow rate of pilot gas sent to the South, North, and Acid Gas Flares can be calculated based on continuous pressure monitoring and design information for nozzle size at the flare tip. The volumetric flow rate of purge gas (refinery fuel gas) to the Acid Gas Flare is continuously monitored and recorded with flow meter 21F034. The volumetric flow rate monitor for gases that are flared at the Acid Gas Flare (21F254) does not include the purge gas. There is no purge gas sent to the South and North Flares.

**2.3.3 Pilot Monitoring**

In accordance with Regulation 12-11-503, the South, North, and Acid Gas Flares are each equipped with a continuous burning pilot. The presence of a flame is continuously monitored with temperature monitors including 21T059 through 21T064 at the South Flare, 21T055 through 21T058 at the North Flare, and 21T065 through 21T068 at the Acid Gas Flare.

**2.3.4 Flare Video Monitoring**

The South, North, and Acid Gas Flares are video monitored in accordance with Regulation 12-11-507. A real-time digital image of each flare and flame are maintained with a frame rate of at least 1 frame per minute. The recorded image of the flare and flame are of sufficient size, contrast, and resolution to be readily apparent in the overall image. The image includes an embedded date and time stamp.

**2.3.5 Flare Seal Drum Monitoring**

In accordance with Regulation 12-12-501, water seal integrity monitors were installed prior to August 1, 2006 at the seal drums for the South, North and Acid Gas Flares (D-2105, D-2112, and D-2106). For each water seal drum, these instruments continuously monitor the water level and the water seal (pressure differential between the flare header and seal drum). Tables 6 and 7 provide specifications for the flare seal drum monitors.

**Table 6**  
**Flare Seal Drum Level Monitors**

<b>Flare &amp; Seal Drum</b>	<b>Level Monitor</b>	<b>Range (inches)</b>	<b>Location of 0 inches</b>
South Flare, D-2105	21L014	0 to 56	2" below top of "H" sparger
North Flare, D-2112	21L015	0 to 46	2" above top of "H" sparger
Acid Gas Flare, D-2106	21L013	0 to 33	11" below dip leg opening

**Table 7**  
**Water Seal Monitors<sup>(1)</sup>**

Flare & Seal Drum	Level Monitor	Range (inches of water)
South Flare, D-2105	21P070	0 to 50
North Flare, D-2112	21P071	0 to 50
Acid Gas Flare, D-2106	21P069	0 to 10

<sup>(1)</sup>Pressure differential between the flare header and the seal drum.

### 2.3.6 Flare Gas Composition Monitoring

In accordance with Regulation 12-11-502, the Benicia Refinery monitors the composition of any gases that result in a reportable flaring event and submits compositional information to the BAAQMD when reports are submitted. Flaring events are defined as continuous events sensed by the Panametric flare flow meters in excess of 330 scfm (0.475 mmscfd) for 15 continuous minutes or longer. Regulation 12-11-502.3.1.a requires that a sample be taken within 15 minutes of the start of a flaring event, and at three hour intervals during a flaring event.

An automatic flare sampler is installed on the main Flare Gas Header to capture these samples. When sampling is required pursuant to Regulation 12-11-502, the samples are analyzed by gas chromatograph at an onsite laboratory to determine the gas composition. From this information gas composition is derived including the gas molecular weight, Btu content, non-methane hydrocarbon content, and hydrogen sulfide content.

Sampling is not conducted at the Acid Gas Flare to determine composition. In accordance with Regulation 12-11-502.3.1.a, composition data representing worst-case conditions has been provided to the BAAQMD.

Detailed process and instrumentation diagrams of the automatic flare sampling system (Drawing Nos. 131-KE-19, 136-KD-7A, and 136-KD-7B) are provided in Appendix C.

### 2.3.7 Flare Gas Compressor Monitoring

Flare Gas Compressor C-2101 A suction is monitored by temperature (21T007) and pressure (21P018), which are located on the overhead of D-2114 suction KO drum. Compressor discharge is monitored by temperature (21T018), pressure (21P022), and flow (21F026), which are located on the overhead of the D-2117 3<sup>rd</sup> stage KO drum. An O<sub>2</sub> analyzer (21A002) for monitoring the O<sub>2</sub> content of recovered flare gas is located on the overhead of D-2115 1<sup>st</sup> stage discharge KO drum.

Flare Gas Compressor C-2101 B suction is monitored by temperature (21T034) and pressure (21P036), which are located on the overhead of D-2119 suction KO drum. Compressor discharge is monitored by temperature (21T029), pressure

(21P040), and flow (21F226), which are located on the overhead of the D-2121 2<sup>nd</sup> stage KO drum. An O<sub>2</sub> analyzer (21A004) for monitoring the O<sub>2</sub> content of recovered flare gas is located on the overhead of D-2120 1<sup>st</sup> stage discharge KO drum.

Suction pressure (Flare Gas Header pressure) of each compressor is controlled by adjusting recycle flow. Compressor loading (0, 25, 50, 75 and 100 percent steps) in turn is adjusted to maintain the recycle valve in controllable range.

Both compressors are equipped with independent instrumentation on the suction, discharge, and inter-stages, to trip the compressors if certain operating parameters are exceeded. Compressor trip set points are discussed in Section 2.1.2 and summarized in Table 4.

Detailed piping and instrumentation diagrams that include instrumentation for monitoring the Flare Gas Compressor operation (Drawings Nos. 36-000-03E-03537 and 36-000-03E-09061 for C-2101 A; Drawing Nos. 36-000-03E-09060 and 36-000-03E-09061 for C-2101 B) are provided in Appendix C.