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September 30, 2025

Jeff Gove
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Bay Area Air District
375 Beale Street, Suite 600
San Francisco, CA 94105

Annual Update of Flare Minimization Plan - Public
Chevron Richmond Refinery

Dear Mr. Gove:

Attached please find the annual update of Chevron's Flare Minimization Plan (FMP).

The contents of Appendices A, B, C, and D in this public version of this FMP have been blocked out. Full copies of updated Appendices A, B, C, and D will be included in a Trade Secret transmittal of the FMP, provided under separate cover.

Trade Secret Information

Appendices A through D to this FMP contain confidential business information and are trade secrets of Chevron Products Company, a division of Chevron U.S.A. Inc, as defined by the California Public Records Act, Government Code Section 6254.7 et seq., and 40 CFR Part 2, Subpart B, 18 USC 1905 and 5 USC 552(b)(4). This response is protected from public disclosure under California law, including Government Code Section § 6254.7, and the District's procedures in Section 11 of the District's Administrative Code. Because of the sensitive and competitive nature of the information, Chevron Products Company requests that the BAAQMD afford the information Confidential Business Information treatment indefinitely.

If you have any questions, please contact Wilma Dreessen at wilma.dreessen@chevron.com or at 510-242-2894.

Sincerely,

For Kris Battleson

Attachments

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Flare Minimization Plan

Chevron Products Company - Richmond Refinery

Public Version



CHEVRON PRODUCTS COMPANY

Flare Minimization Plan

Richmond Refinery

Submitted to

Bay Area Air District

Updated September 30, 2025

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Certification Statement

Based on information and belief formed after reasonable inquiry, I, Richmond Refinery HSE Manager, certify that the flare minimization plan is accurate, true, and complete.


_____ for Kris Battleson 9/30/2025
Signature Date

Executive Summary

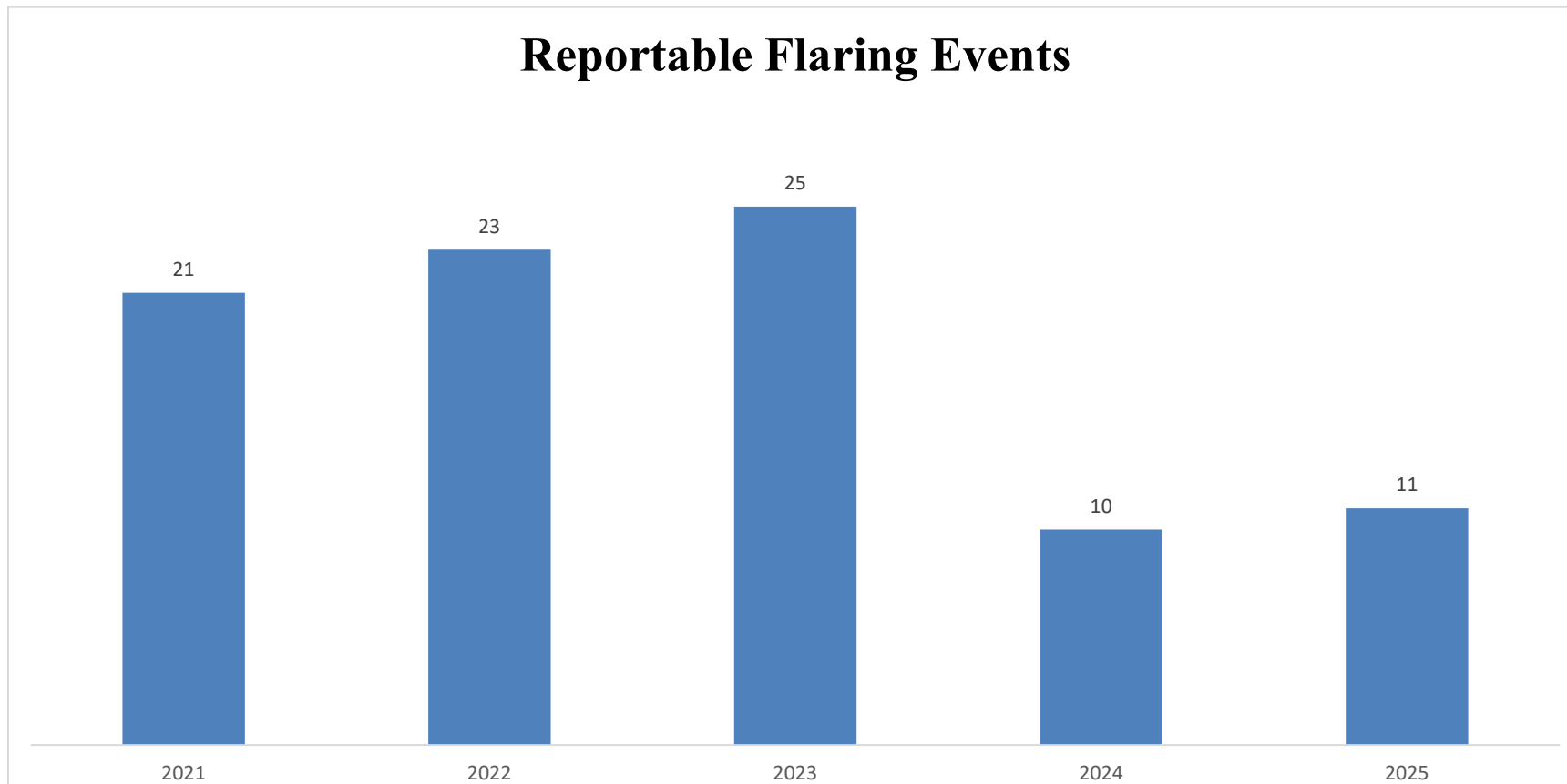
This Flare Minimization Plan (FMP) for the Chevron Richmond Refinery (the “Richmond Refinery”) is provided pursuant to the requirements of Regulation 12, Rule 12, which was adopted by the Bay Area Air District (BAAD) on July 20, 2005. The FMP defines a series of measures intended to reduce flaring to the extent that is feasible without compromising safety and necessary refinery operations and practices. It is the Richmond Refinery’s policy that flare events will only occur within the scope of Reg. 12-12, and that we will adjust the operation of process units to prevent flaring when consistent with safe and reliable operations.

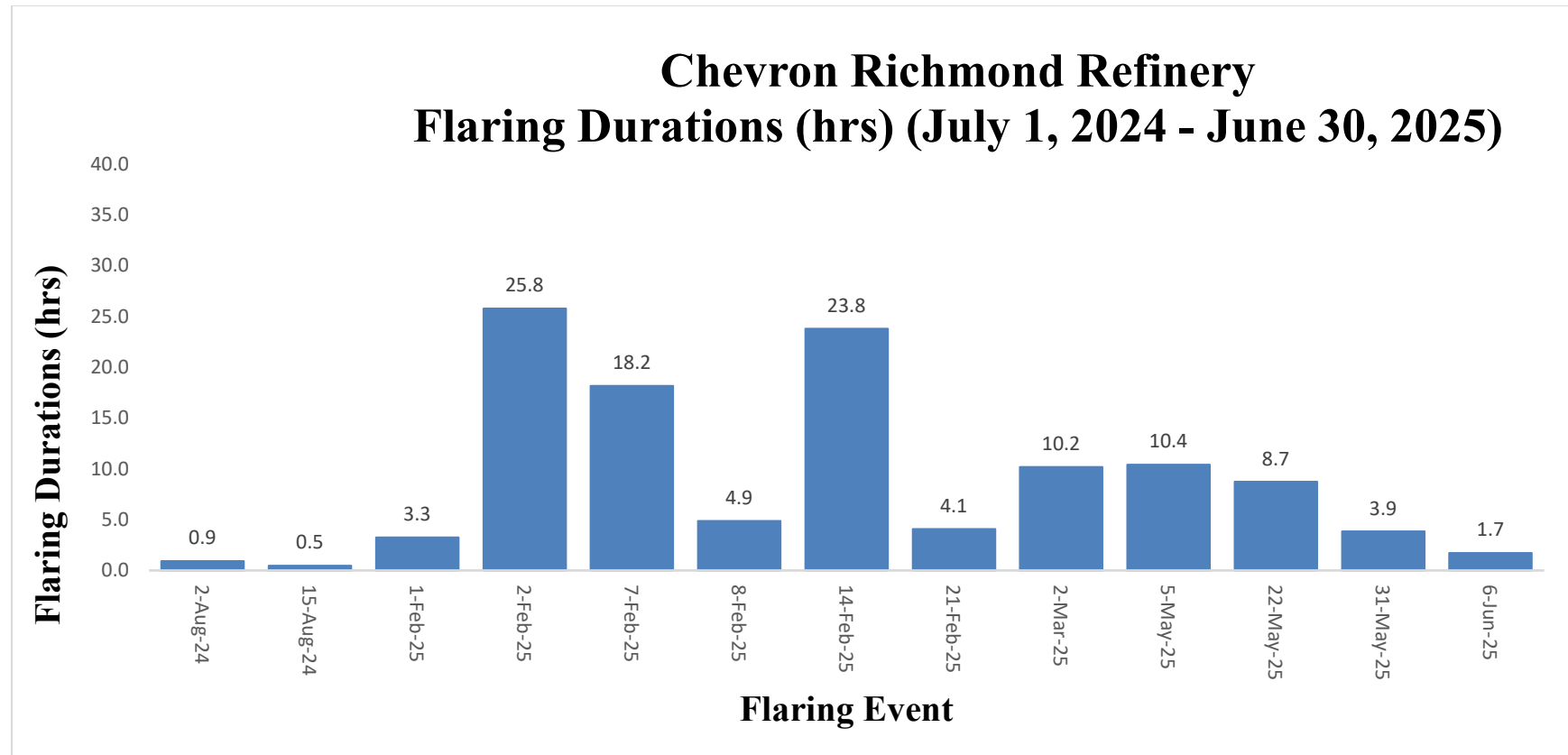
Time Period Covered by the FMP Update (the “FMP Year”)

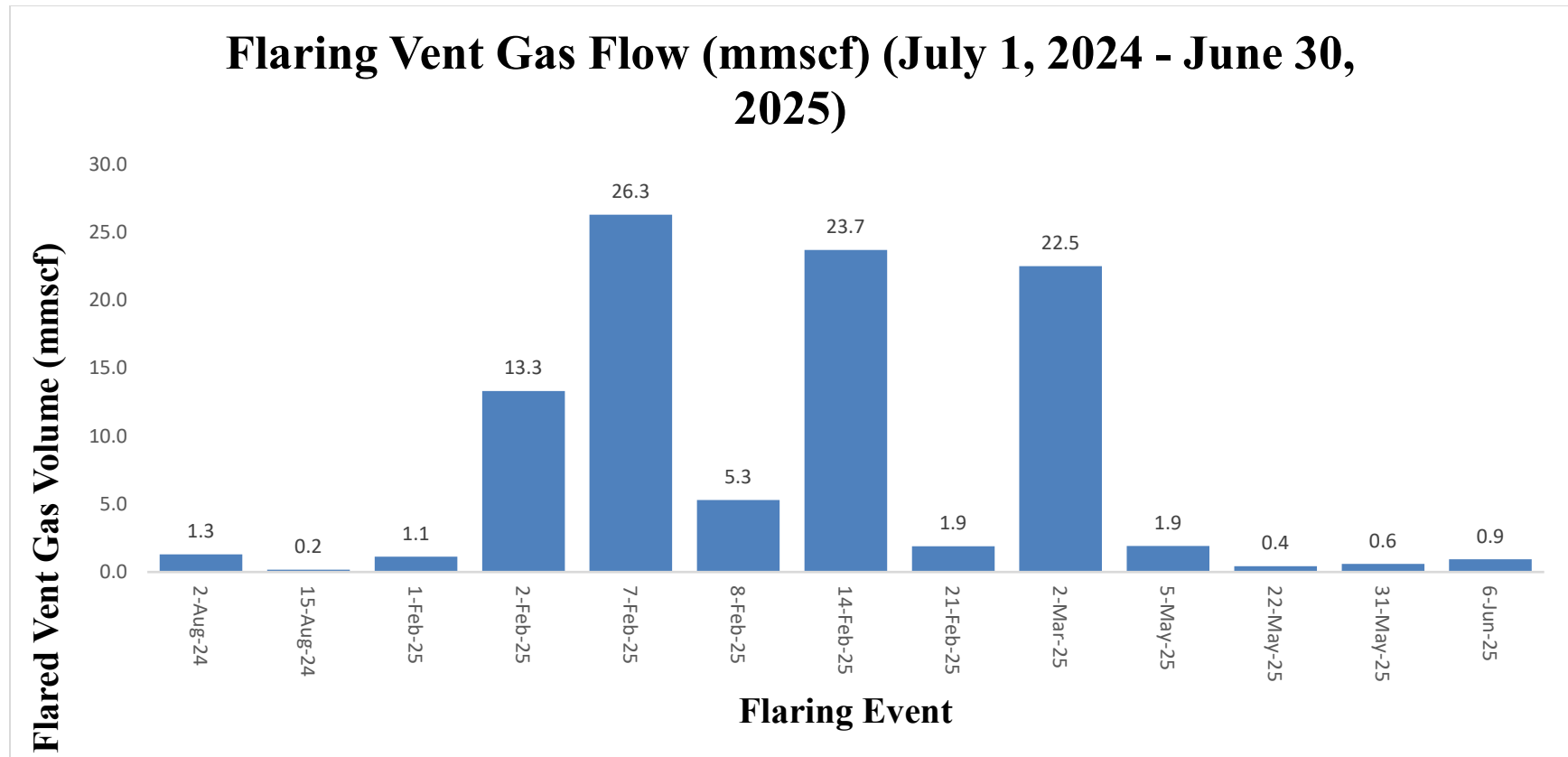
Pursuant to Regulation 12, Rule 12, Section 404.1 (12-12-404.1), the Annual Update is due 12 months after approval of the initial FMP and annually thereafter. To ensure consistency the FMP updates are due no later than October 1 each year. The FMP update due October 1, 2025, covers the 12-month period from July 1, 2024, to June 30, 2025.

Graphics Depicting Progress of Flare Minimization

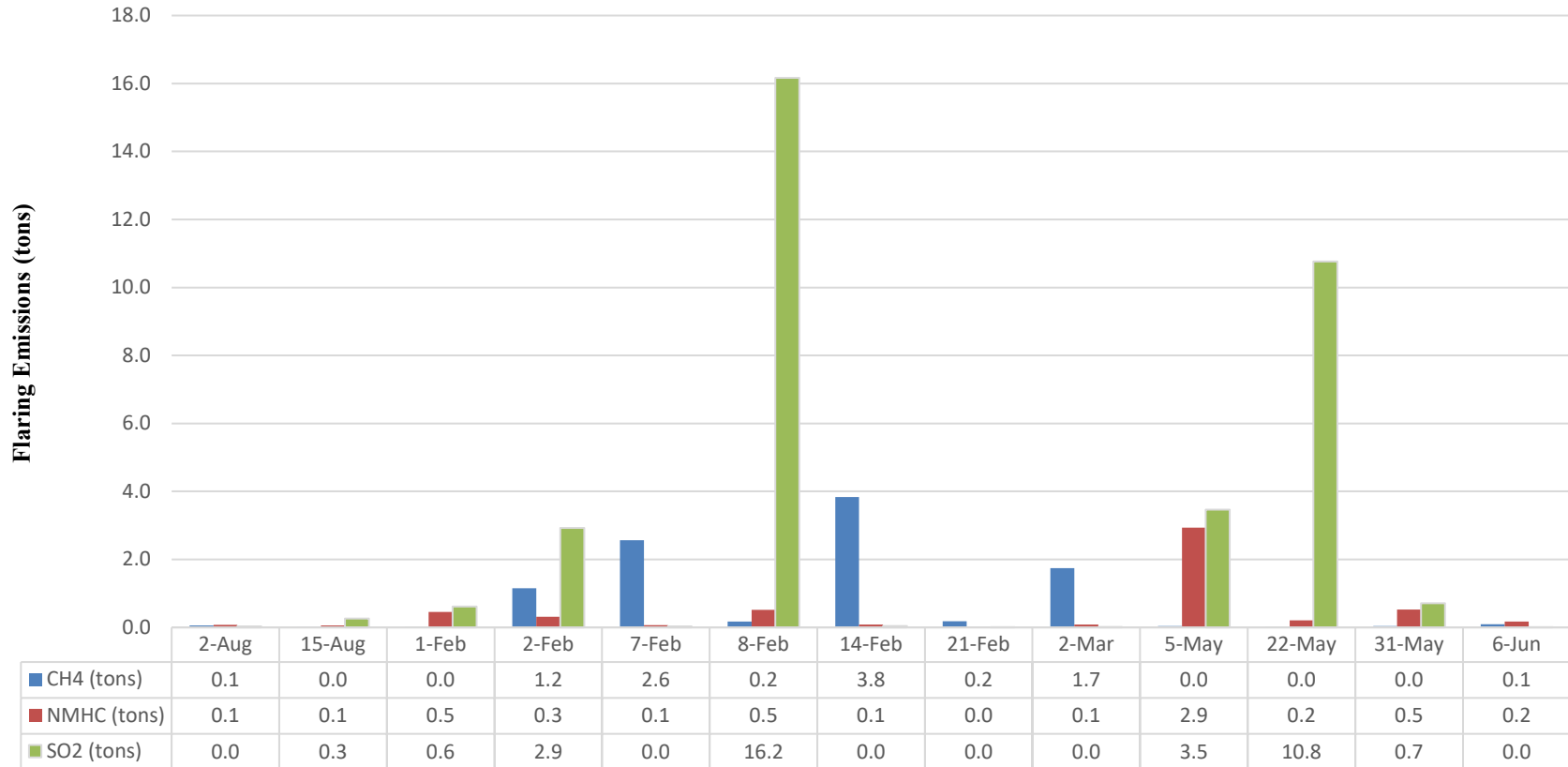
The first graph displays the number of reportable flaring events per Regulation 12-12 for the last 5 years. The second graph displays the flaring duration, in hours, of each reportable flaring event that occurred from July 1, 2024 to June 30, 2025. The third graph displays the total flared vent gas volume of each reportable flaring event that occurred from July 1, 2024 to June 30, 2025. The last graph displays the total methane, non-methane hydrocarbon (NMHC), and sulfur dioxide (SO₂) emissions for each reportable flaring event that occurred from July 1, 2024 to June 30, 2025.







Flaring Emissions (tons) (July 1, 2024 - June 30, 2025)



Discussion of Flare Reductions and New or Amended Prevention Measures

Vent gas flow and emissions of methane and non-methane hydrocarbons significantly decreased compared to the previous FMP period (July 1, 2023 – June 30, 2024). SO₂ emissions were higher due to some events having a higher quantity of H₂S in the process gas being flared. Table 1 quantifies the change in vent gas and emissions from the previous FMP period (July 1, 2023 – June 30, 2024) to the current FMP period (July 1, 2024 – June 30, 2025).:

<i>Flaring Duration</i>	<i>Vent Gas</i>	<i>Methane</i>	<i>NMHC</i>	<i>SO₂</i>
-39%	-53%	- 53%	-19%	+272%

Chevron continues to place an ongoing, refinery-wide emphasis on minimizing flaring and additional reductions during planned maintenance activities through the following three primary focus areas: (1) source control program, (2) equipment and process unit reliability, and (3) planned maintenance practices.

The Refinery's source control program identifies sources contributing to the volume of gases going to the relief system that may be re-routed, mitigated or eliminated. Minimizing sources to the relief system decreases average loading on the Flare Gas Recovery (FGR) compressors, increasing FGR available capacity to be used to capture gases for emergency situations. For example, during this reporting period, sources that contribute to the FGR were identified and reduced thus increasing the available capacity of FGR compressors.

A key aspect in the operation of the Refinery is a refinery-wide program that focuses on the reliability of equipment and process units. Investments in equipment reliability directly contribute to flare minimization. For example, during this period, source control efforts have identified several valves in the process units that were leaking process gas into the relief system and required maintenance. This and similar actions result in reliable operation and minimization of the contributions to the flare gas compressors.

Historically, planned maintenance events accounted for a substantial portion of Richmond's flaring activity. As a result, a variety of enhancements have been made to the Refinery's practices for relief system management during planned maintenance. Examples are: (1) using temporary condensing equipment to decrease the impact of steaming equipment to relief and (2) staggering the vessel depressurizing schedule to minimize load on the relief system. In addition, planned maintenance scopes of work are evaluated for opportunities to minimize the potential for flaring and a project "flare plan" is created. Where feasible, schedules of the maintenance activities are adjusted so that the potential to flare is minimized. For example, during this period, the Refinery has dedicated engineering resources to ensure any upcoming major maintenance event is prepared to minimize and, at times, eliminate flaring by altering the scheduled depressurizing of process vessels.

In addition to these proactive elements of the Refinery's flare minimization program, Operations' approach in responding to equipment malfunctions and unplanned shutdowns is having a positive impact on the reduction of flaring. The emergency procedures and Operations' responses to unplanned situations include a focus on the impact to the relief system and how to take the necessary operational actions, while maximizing relief gas recovery and consequently minimizing flaring. In some cases, flaring cannot be avoided, and the flares are used to protect the safety of equipment, personnel, and the environment. Added flexibility in the Refinery's relief gas recovery system, including dual service compressors that can support the relief

system when needed, provides Operations with more flexibility when responding to emergency situations. Lastly, Chevron identifies all flaring activities for the purpose of reporting vent gas volume and emissions in accordance Regulation 12, Rule 11. For flare activities below BAAD thresholds that would trigger causal analysis, Chevron continues to identify the cause(s) for all flare activities and implement lessons learned that can improve flare minimization efforts and overall flare performance.

The following updates to the Flare Minimization Plan identify planned additions and modifications of equipment described in Regulation 12-12-401.1.1.

1.0 Introduction

This Flare Minimization Plan (FMP) for the Chevron Richmond Refinery (the “Richmond Refinery”) is provided pursuant to the requirements of Regulation 12, Rule 12 (Reg. 12-12), which was adopted by the Bay Area Air District (BAAD) on July 20, 2005. The FMP defines a series of measures intended to reduce flaring to the extent that is feasible without compromising safety and necessary refinery operations and practices. It is the Richmond Refinery’s policy that flaring events will only occur within the scope of Reg. 12-12, and that we will adjust the operation of process units to prevent flaring when consistent with safe and reliable operations. This FMP addresses all the applicable requirements of Regulation 12, Rule 12, Section 400. Certain requirements related to historical operations are not applicable, since the Hydrogen Plant and the Hydrogen Plant flare began operating in 2018.

Reg. 12-12 prohibits flaring “unless it is consistent with an approved FMP and all commitments under that plan have been met.” BAAD 12-12-301. For purposes of this regulation, flaring is defined as “the combustion of vent gas in a flare,” [Reg. 12-12-203], and “vent gas” is defined as “any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases,” [Reg. 12-12-213]. The FMP does not apply to flaring that the APCO determines to be “caused by an emergency and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere” [Reg. 12-12-301].

The key approaches used to reduce flaring include planning efforts focused at flare minimization coupled with evaluation of the causes of flaring events that do occur and implementing corrective actions from those events. By using this approach and having an understanding of the causes of flaring events, we can incorporate the lessons learned into future planning and flare minimization efforts. The FMP also examines the costs and benefits of potential equipment modifications to increase flare gas recovery.

Hydrogen Plant Flare

The Hydrogen Plant flare (S-6021) is mainly required for safety reasons. The flare system is designed to handle excess gases in the event of a safety-related rapid unit depressurization at the Hydrogen Plant. There will be no routine flaring operations. The flare is operated infrequently in accordance with Part 28 of the Authority to Construct for the Richmond Modernization Project (BAAD Application #12842-Condition #24136) and this plan. The primary purpose of the flare is for the combustion of gas streams that could otherwise pose a significant safety hazard if released at the refinery. The use of a refinery flare for safety reasons is consistent with Regulation 12, Rule 12, Section 101.

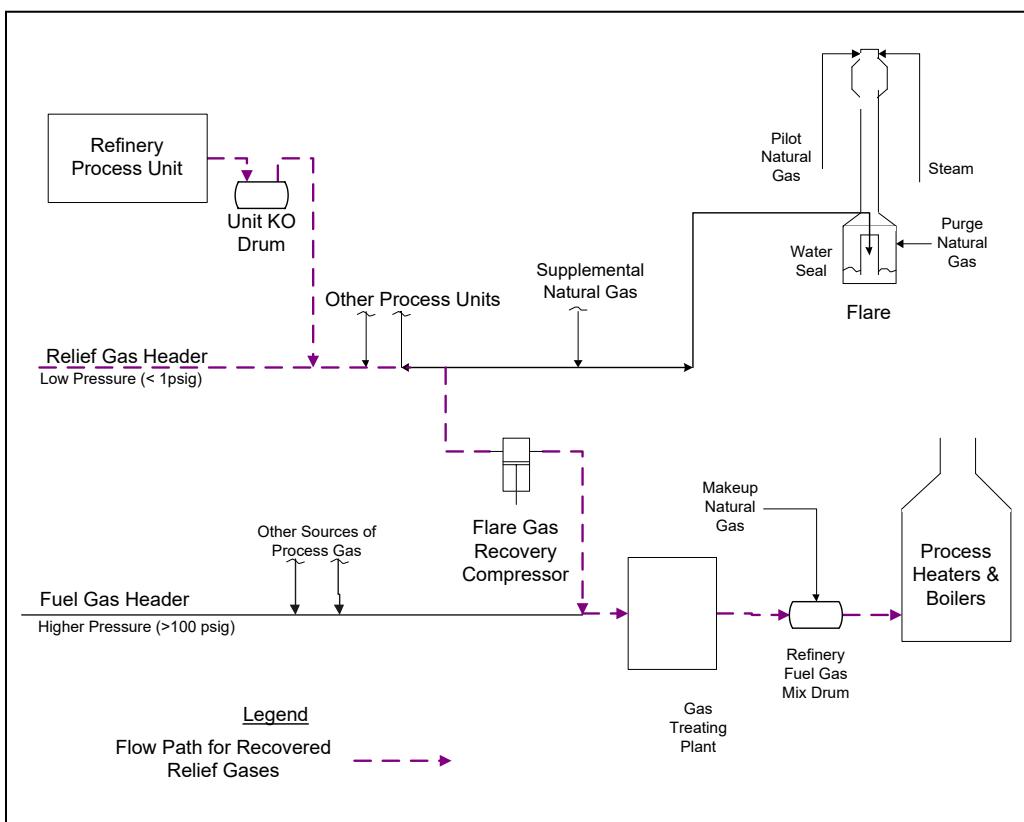
The potential use of the existing refinery North and South Yard flare systems to flare gas streams from the new Hydrogen Plant was evaluated, and it was determined that this option is not feasible because of the distance to existing refinery flare systems. The relief gases from the previous hydrogen plant, being replaced by the new plant, were routed to source S-6012 at the refinery, so any flaring occurring at the Hydrogen Plant flare will be balanced by a reduction in flaring from flare S-6012. The new Hydrogen Plant has proven to be more efficient and more reliable than the previous plant and has led to an overall reduction in flaring events. As a result, the use of the new Hydrogen Plant flare is consistent with refinery flare minimization.

The Authority to Construct for the Richmond Modernization Project, including the new Hydrogen Plant, was reissued on February 11, 2015 (Plant No. A0010, Application No. 12842 - Condition #24136). The Hydrogen Plant Flare started up on October 24, 2018.

1.1 Background Information on Flare Systems

The following section describes how gases are generated and handled by refinery flare systems. A simplified schematic of a refinery flare system with flare gas recovery is shown in Figure 1-1.

Figure 1-1, Simple Schematic - Flare System with Flare Gas Recovery



Refineries process crude oil by separating it into a range of components, or fractions, and then processing those components to produce a planned yield of desired refined products. Petroleum fractions include heavy oils and residual materials used to make fuel oil, mid-range materials such as diesel, jet fuel and gasoline, and lighter products such as butane, propane, and fuel gases.

A typical refinery is organized into groups of process units, with the general goal of maximizing the production of transportation fuels – gasoline range materials in the summer; distillate (jet and diesel) range materials in the winter. 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. Many of these processes operate at elevated temperatures and pressures, and a critical element of safe design is having the capability of releasing excess pressure via relieving devices to the relief gas header to return processes to a safe posture in a controlled manner. 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 environmental specifications such as reduced sulfur levels.

The Richmond Refinery requires hydrogen in operating processes and for other uses. Hydrogen is used in refining to increase the fraction of crude oil which can be used to produce gasoline as well as other higher-value petroleum products. Hydrogen is also used in conjunction with a desulfurization catalyst to remove sulfur and nitrogen from hydrocarbon products.

North and South Yard Flare Systems

Refineries are designed and operated so that there will be an optimum balance between the rates of gas production and consumption. Under normal operations, gases that are not recovered as products (predominantly methane, ethane, and hydrogen) are routed to the refinery fuel gas system, allowing them to be used for combustion in refinery heaters and boilers. Typical refinery fuel gas systems are configured so that the fuel gas pressure is maintained by making up with purchased natural gas to meet the net fuel requirement. This provides a simple way to keep the system in balance so long as gas needs exceed the volume of gaseous products produced. Some additional operational flexibility is typically maintained by having the ability to burn other fuels such as propane or butane and having the capability to adjust the rate of fuel gas consumption to a limited extent at the various refinery users (e.g., heaters, boilers, cogeneration units, steam turbines).

A header for collection of vapor streams is included as an essential element of nearly every refinery process unit. At the Richmond Refinery, these are typically referred to as "relief gas headers", since the system, which is generally at near-atmospheric pressure conditions, receives gases "relieved" from higher pressure operations within the unit. The primary function of the relief gas header is safety. It provides the process unit with a readily available and controlled means of releasing gases to prevent over-pressurization of equipment (routing them to controlled locations for destruction by combustion). It also provides a controlled outlet for any excess vapor flow, nearly all of which is flammable, making it an essential safety feature of every refinery. Each relief gas header has connections for equipment depressurization and purging related to maintenance turnaround, startup, and shutdown, as well as pressure relief devices and other safety control valves to handle upsets, malfunctions, and emergency releases.

It is common practice for the process unit's relief gas header to incorporate a knockout drum for separation of entrained liquid at the unit boundary. This minimizes the possibility of liquid being carried forward to the flare or flare gas compressor. Liquids cause serious damage to most types of compressors and cannot be safely and completely burned in a flare. Liquids (condensed water and any entrained hydrocarbon liquids) from the unit knockout drum are sent to sour water handling facilities. The vapor stream from the knockout drum is routed to a flare gas recovery system.

A typical refinery flare system consists of a series of branch lines from various unit collection systems which join a main relief gas header. The main relief gas header is, in turn, connected to both a flare gas recovery system and to one or more flares. Normally all vapor flow to the relief gas header is recovered by flare gas recovery compressors, which increases the pressure of the flare gas allowing it to be first routed to a gas treater for removal of contaminants such as sulfur and then delivered to the refinery fuel gas system. Gas in excess of what can be handled by the flare gas recovery compressor(s), the treater(s), and/or the fuel gas system end users is directed to a refinery flare so it can be safely combusted.

A flare water seal is located in the bottom of each flare in the North Yard and South Yard relief systems to serve several functions. The flare seal is a dam of water that is maintained in the bottom of the flare to create a barrier through which the gas must cross in order to go out of the

flare stack. The depth of liquid maintained in the seal determines the pressure that the gas must reach in the relief gas header before it can exit the flare. The flare seal creates a positive barrier between the header and the flare, ensuring that gas from the relief gas header will not go to the flare if the flare gas recovery system can keep pace with the net gas production. It also guarantees a positive pressure at all points along the relief gas header, eliminating the possibility of air leakage into the system. Finally, it provides a positive seal to isolate the top of the flare, which is an ignition source, from the relief gas header and the process units. Some flare systems combine multiple flares with a range of water seal depths, effectively “staging” operation of the various flares. At the Richmond Refinery, such staging is configured to favor the recovery of relief gases with the highest sulfur concentrations so that the first gases flared would be those lower in sulfur content.

A flare molecular seal is located at the top of each flare near the flare tip and is designed to minimize the amount of purge gas sent to the flare. Purge gas is used to prevent oxygen from entering the flare and creating a safety issue. Like a water seal, the molecular seal serves to protect the stack from flame front or flash back. Molecular seals work based on the difference between the density of the air and hydrocarbon mixture.

Gases exit the flare via a tip, which is designed to promote proper combustion over a range of gas flow rates. Steam is used to increase mixing between air and hydrocarbon vapors at the flare tip, so as to improve the efficiency of combustion and reduce smoking. The combustion efficiency for steam-assisted flares is high even when some smoking is present – generally over 97% according to some references. A continuous flow of natural gas to the flare is required for two reasons. Natural gas pilot flames are kept burning at all times at the flare tip to ignite any gas exiting the flare. Additionally, a small flow of “purge” gas is required to maintain a positive upwards flow and prevent air from being sucked back into the flare stack where it could create an explosive environment. Purge gas is generally either nitrogen (an inert gas) or an easily combusted gas – the Richmond Refinery uses natural gas for its purge flows.

The Refinery has installed supplemental natural gas that is used during flaring events to support compliance with the net heating value requirements at the combustion zone in 40 CFR 63 Subpart CC.

The sources of normal or base level flow to a refinery flare gas collection system are varied, generally small contributions, and include sources such as: leaking relief valves awaiting maintenance, instrument purges, and pressure control for refinery equipment items (e.g., overhead systems for distillation columns). Added to this low-level base load are small spikes in flow from routine maintenance operations, such as clearing hydrocarbon from a pump or filter by displacing volatiles to the relief gas header with nitrogen or steam, or blowing down knockout drums. Additional flare load results from routine process functions, often related to operation of batch or semi-batch operations.

Hydrogen Plant Flare System

This section describes how gases are handled by the Hydrogen Plant flare systems. The Hydrogen Plant flare (S-6021) is designed to safely treat any unplanned over-pressurization of the processing streams and the CO, hydrogen, and methane vented during startup and shutdown in the Hydrogen Plant trains by combusting them prior to release into the atmosphere. To burn the released process gases the flare maintains a pilot burner that is supplied with natural gas and is operating at all times.

The Hydrogen Plant flare is equipped with a velocity seal. The velocity seal is a Venturi type restriction located near the end of the flare. The seal locally increases the velocity of the sweep

gas, preventing air from entering the flare. The velocity seal is very reliable and requires minimal maintenance.

Gases exit the flare via a tip which is designed to promote proper combustion over a range of gas flow rates. The flare is steam assisted and has precursor organic compound destruction efficiency of at least 98%. Natural gas pilot flames are kept burning at all times at the flare tip to ignite any gas exiting the flare. Additionally, a flow of sweep gas is required to maintain a positive upwards flow and prevent air ingress into the flare stack where it could create an explosive environment. The Hydrogen Plant uses natural gas for sweep flows. The flare is designed with a steam assist. In the unlikely event that any smoke is created during flaring, steam will increase combustion efficiency and mitigate visible emissions.

General Flare Systems

Maintenance activities can also result in higher-than-normal flow of material to relief systems. Maintenance activities require removing (purging) all hydrocarbon from process equipment, associated piping, and catalyst loads. This is done to address employee and equipment safety concerns, and for environmental compliance. Procedures to prepare equipment for maintenance include multiple steps of depressurization and purging with nitrogen or steam to the relief gas header. Efforts are made to recover as much relief gas as technically possible. However, because of sound engineering principles, it is not always feasible to recover 100% of the relief gas generated. For example, gases such as nitrogen with higher heats of compression can cause overheating, resulting in damage to flare gas recovery compressor parts. Nitrogen would also lower the heating value of refinery fuel gas and greatly affect performance of fired process heaters throughout the refinery.

Flares are first and foremost safety devices intended to prevent emissions of air contaminants directly to atmosphere and/or catastrophic events, both of which would have serious, adverse effects on air quality, as well as the health and safety of refinery workers and surrounding communities. Refineries have a general duty to maintain the safe and reliable operation of flares and flare systems. These systems must be continuously capable of collecting and safely combusting hydrocarbons from pressure-relieving and vapor depressurizing units throughout all startup, shutdown, upset, or malfunction conditions. Most major flare maintenance activities necessarily must occur during a turnaround. Other maintenance activities, including preventative maintenance activities, occur while the flares and flare systems are in service. Operations routinely monitor pilot and purge, steam assist, water flow to the flare water seal, water seal integrity (see Section 2.3.2), water seal overflow, and level transmitters. Liquid hydrocarbons that become trapped in the molecular seal or that accumulate in the water seal can impair system integrity and can create safety hazards. Steam is injected, as appropriate, to remove hydrocarbon liquids and other obstructions from these seals and ancillary equipment, consistent with flare manufacturer recommendations and API/ANSI Standard 521. Knockout drums are located at the base of the flare to catch any condensable that may be present.

1.2 Trade Secret Information

Appendices A, B, C, and D to this FMP contain refinery-confidential information and are trade secrets of Chevron Products Company (Chevron), as defined by the California Public Records Act, Government Code Section 6254.7 et seq., and 40 CFR Part 2, Subpart B, 18 USC 1905 and 5 USC 552(b)(4). Because of the sensitive and competitive nature of the information, Chevron Products Company requests that the BAAD afford the information Confidential Business Information treatment indefinitely. The contents of Appendices A, B, C, and D in the public version of this FMP have been blocked out. Full copies of Appendices A, B, C, and D are included in this Trade Secret transmittal of the FMP, provided under separate cover.

2.0 Technical Data

Pursuant to the requirements of Regulation 12, Rule 12, Section 401.1, the following section provides descriptions and technical information for the flare systems as well as the upstream equipment and processes that send gas to the flares at the Richmond Refinery.

2.1 Description of Flaring Systems

The Richmond Refinery operates three flare systems, one covering the North Yard of the refinery, one covering the South Yard of the refinery, and one flare system for the Hydrogen Plant. Simplified Flow Diagrams for each of these systems are listed in the following Table 2-1, and are included in Appendix A to this document.

Table 2-1 Flare System Drawings (refer to Appendix A)

<i>Drawing No.</i>	<i>Drawing Version</i>	<i>Drawing Title</i>
NY-1	September 8, 2020	North Yard Relief System
SY-1	December 28, 2011	South Yard Relief System
D-382664-A	July 31, 2017	Simplified Flow Diagram – Hydrogen Plant Flare

North Yard

The North Yard flare system has a Flare Gas Recovery (FGR) system designed to recover all of the relief gases. If the flare gas compressors become fully loaded (e.g., due to a process upset), the North Yard flares can be preferentially diverted away from FGR in order to recover the streams with the highest sulfur content and; therefore, minimize sulfur compound emissions. Flare water seal heights are set to allow this staggered flare operation. The water seal heights are subject to process variability. The North Yard flares are staggered in the following priority:

- FCC - 18" water height The FCC and Alky-Poly flares are connected by a 30" relief line. The Alky-Poly flare, with 20" water seal height, sees flow only after the relief line pressure overcomes its water seal. The FCC Flare is set to relieve first with the Alky-Poly Flare set to relieve second. Based upon their respective location in the staged system, the FCC Flare would be expected to receive relief gases with lower sulfur content. The Alky-Poly flare would be expected to receive gases with higher sulfur content.
- South Isomax - 24" water seal height
- North Isomax - 24" water seal height
- RLOP - 24" water seal height

This order corresponds to flares that handle streams with increasing sulfur content, note, this preferential selection is different from cascading multiple flares on the same header. Individual flare capacity is not affected by this, as maximum flow at the flare tip for the power failure case is the same whether individual or multiple flares are operating. Episodic events and plant cleanups that require relief through the individual flares would preclude the option to preferentially select the flares.

The North Yard has three compressors available for dedicated flare gas recovery service. Compressors K-1060 and K-1070 each have a recovery capacity of 4 MMSCFD at 100% loading. K-1960 takes load off the North Yard Flare Gas Recovery (FGR) system by recovering vented hydrocarbons from the RLOP units, handling 1.3 MMSCFD of gas.

Since overhauls and upgrades to K-1060 and K-1070 were completed in January 2004, and K-1960 was re-commissioned in February 2006, reliability has been sustained on all three compressors, and preventative and proactive maintenance has been performed without causing flaring. In the event the primary compressor and K-1960 are down, either K-1060 or K-1070 therefore provides reliable, dedicated back-up with 4.0 MMSCFD capacity.

The North Yard FGR compressors K-1060 and K-1070 are manually controlled by the South Isomax operating crew. A compressor suction pressure of eight inches of water is normally targeted. The suction pressure of the FGR system controls the flare header pressure for the North Yard flares that are manifolded to the FGR system. The suction pressure is maintained by setting the valve loading at one of five fixed values: 0, 50, 57, 80 or 100% of load. Compressor discharge gas temperature is alarmed at 325 Deg F to prevent compressor damage.

RLOP Vent Gas compressor K-1960 uses four controllers to control suction at atmospheric pressure. K-1960 is loaded and unloaded using logic. This allows loading at one of five fixed values: 0, 20, 45, 75 or 100% of load. K-1960 has a recovery capacity of 1.29 MMSCFD at 100% loading and will normally run 100% loaded. Additionally, K-1960 can also be loaded and unloaded manually.

K-1060 and K-1070 have permanent sensors mounted which provide monitoring and trending of vibration and compressor performance. All FGR Compressors are also monitored, at a minimum, on a weekly basis and on an increased frequency if the parameters monitored indicate that more frequent monitoring is needed. The frequency of increased monitoring is contingent upon the unit data and history.

Either K-1060 or K-1070 compressor can serve as a spare, and schedules for preventive maintenance (PM) work are based on monitoring data. K-1960 is spared by either K-1060 or K-1070 and PM is based on monitoring data.

The North Yard Flare System is connected to relief systems from process units located in the Cracking, Hydro-processing and RLOP (Richmond Lube Oil Project) divisions. There are five active Flares in the North Yard Flare System. These flares, and the process units associated with each, are listed in Table 2-2.

Table 2-2 North Yard Flare System Plant Sources

<i>BAAD Flare No.</i>	<i>Flare Name</i>	<i>Process Units</i>
S-6016	FCC (Note 1)	S-4285, Fluidized Catalytic Cracking Plant (FCC) S-4286, FCC Gas Recovery Unit (FCC GRU) S-4433, 3H2S
S-6019	Alky-Poly (Note 1)	S-4291, H2SO4 Alkylation Plant (Alky) S-4292, Propylene Polymer Plant (Poly) S-4354, Butamer Plant S-4355, Deisobutanizer Plant (Yard DIB)

		S-6050, MTBE Plant S-4356, TAME Plant S-4227, Sulfur Recovery Unit (SRU) #1 S-4228, Sulfur Recovery Unit (SRU) #2 S-4229, Sulfur Recovery Unit (SRU) #3
S-6039	RLOP	S-4340, Light Neutral Hydrocracker (LNC) S-4341, Light Neutral Hydrofinisher (LNHF) S-4342, Heavy Neutral Hydrocracker (HNC) S-4343, Heavy Neutral Hydrofinisher (HNHF) S-4346, RLOP Gas Recovery Unit (RLOP GRU) S-4345, #18 NH ₃ -H ₂ S Plant S-4454, #6 H ₂ S Plant - Amine Regenerator
S-6013	NISO	S-4252, TKN/Isocracker Plant (TKN/ISO) S4253, TKC Plant S-4429, #8 NH ₃ -H ₂ S Plant S-4434, #4H ₂ S
S-6012	SISO	S-4348, #20 Plant - Hydrogen Recovery S-4250, Hydrogen Manufacturing Plant S-4251, Solvent Deasphalting Plant (SDA) S-4238, LPG Loading Racks (LPG Racks)

Note 1: The FCC and Alky-Poly Flares are linked in a cascade. FCC is the primary flare; Alky-Poly is secondary.

South Yard

The South Yard has two flares, the LSFO Flare and the D&R Flare, connected by a common header. The water seals heights are staggered so that the LSFO Flare should relieve first and the D&R Flare relieves second. The relief system is connected to flare gas recovery as described below.

The South Yard has five compressors available for flare gas recovery service, a dedicated K-3950 plus dual service, process/FGR, compressors, K-1171/K-1171A and K-242/K-252.

The K-3950 South Yard FGR compressor is manually controlled by the D&R East operating crew and services the LSFO and D&R flares. K-3950 has a recovery capacity of 2.35 MMSCFD at 100% loading. The compressor suction pressure is maintained at 7.0 inches water pressure by setting the compressor valves at one of four fixed values: 0, 50, 75 or 100%. The loading can be adjusted locally or remotely from the operator control room. The maximum cylinder discharge temperature is alarmed at 325 deg F. to prevent compressor damage. Compressors K-1171 and K-1171A, at # 4 Crude Unit, are dual-purpose compressors of 1.7 MSCFD capacity each. The primary purpose of K-1171 and K-1171A is to provide pressure control for C-1160 and C-1190 Naphtha Stabilizers in the Crude Unit. Compressors K-1171 and K-1171A can be individually or simultaneously run because they are dual FGR/process service, in order to supplement or spare K-3950 (if K-3950 FGR compressor output is down or limited). The typical annual loading on these compressors is 1.64 MSCFD (or <50% of available capacity). They have a maximum discharge gas temperature of 250 deg F to prevent compressor damage.

K-242 and K-252 compressors were converted for dual process/FGR service in December 2007 to provide additional flare gas recovery capacity in the South Yard. These conversions provide additional and dedicated flare gas recovery compressor capacity as well as reduce the dependency on the dual role K-1171 and K-1171A compressors. K-242 and K-252 compressors are Worthington two-stage, reciprocating units with a capacity of between 1.9 and 2.3 MMSCFD per compressor, depending on the molecular weight of the gas. Either K-242 or

K-252 compressor is available for back-up FGR service (with the other compressor in dual process/FGR service).

K-242/K-252 provide approximately 2.3 MMSCFD dedicated back-up capacity to the existing flare gas recovery capacity of 3 MMSCFD provided by K-3950. With an additional 1.7 MMSCFD available from each of the dual service K-1171 or K-1171A, a total of 7 MMSCFD flare gas recovery capacity is provided against the current base load of 0.8 MMSCFD.

A review of compressor availability from 2003 forward indicates that at least three of the five compressors (K-3950/K-1171/K-1171A, and K-242/K-252) were available for FGR service at all times. The upgrades to K-3950, the availability of K-1171 or K-1171A and the conversion of K-242 and K-252 (see Table 4.1, Planned Improvements) are designed to provide reliable, dedicated and flexible spare capacity.

South Yard Flare Gas Recovery (FGR) Compressor K-3950 had internal upgrades completed in January 2007 to improve its flexibility in handling nitrogen. These included valves with a wider port and larger valve area, and an upgrading to the sealing plates from steel to an engineered plastic. The ammonium salting issue with K-3950 had been resolved after the installation of two carbon drums on the bulk storage perchloroethylene drum off gas line in August, 2007. These upgrades, and the conversion of K-242 and K-252, are designed to provide reliable, dedicated spare capacity.

Schedules for preventive maintenance (PM) work on the K-3950, K-1171/K-1171A and K-242/K-252 are based on monitoring data.

For both North Yard and South Yard FGR systems, if the overall FGR load approaches the capacity of the operating compressor, indication is provided by increasing relief header pressure, which will alarm prior to flaring. If the load increases, or a primary compressor shuts down, the back-up compressor is manually started by field personnel. Once it is confirmed that the back-up compressor is operating, the board operator can load the spare compressor up to 100%. If a primary compressor has shut down, flaring would occur until the spare compressor picks up the full FGR load.

The spare North Yard FGR compressor, either K-1060 or K-1070, is kept on "hot standby". This means that the valving is in position, lube oil and cooling water to jackets are circulating, and steam tracing and nitrogen purge are operating.

For the South Yard FGR compressors, the spare of either K-1171 or K-1171A is kept in the same "hot standby" mode. In certain instances, a valve has to be switched in the field. Compressors K-242 and K-252 are operated in the same way. The spare of either K-242 or K-252 is kept on "hot standby" mode and a valve needs to be switched in the field.

This mode of operation allows the spare compressor to be available and fully loaded within a few minutes if the primary compressor is impacted or unavailable. This mode supports reliable operation through having planned preventative maintenance based on monitoring data for the running compressors and ensuring that the spare compressor is available when needed.

Running the spare FGR compressor on a continual basis would unnecessarily increase operating run time on two machines to recover the same amount of gas. This would increase the risk that a compressor will not be available (due to preventative maintenance servicing / breakdown) when it is needed.

Compressors operate within specific parameters (or operating envelopes). When process flows are at the limits of the compressors operating envelope, additional control measures have to be introduced to maintain reliable process conditions and mechanical integrity. These measures introduce an additional level of complexity to the operation that is not present when one compressor is operating to adequately handle the load.

Having the standby compressor on “hot standby” ensures that if an event takes place that negatively impacts the on-line compressor, then the standby compressor is not exposed to the same adverse conditions and is therefore likely to be available for a quick response if needed.

Operating two compressors in parallel would also waste considerable energy, as these compressors are driven by large motors. K-3950 is driven by a 500 horsepower (HP) motor. K-1060 and K-1070 are driven by 700 HP motors and K-242 / K-252 by 800 HP motors.

During normal flare gas recovery conditions, the loss of the primary flare gas recovery compressor will not necessarily lead to flaring. Flare header pressure operates at slightly above atmospheric pressure, while the water seals on the flares are set at 18” Water Gauge or higher. There is, therefore, a period of time (the duration cannot be defined as it will vary depending on the conditions at the time) before the system pressure in the flare gas recovery header exceeds the water seal pressure, which allows for a period of time in order to start the standby compressor.

The current effective and reliable operation requires having a spare compressor. There is no benefit to run the spare compressors as long as the FGR load does not exceed the capacity of the current FGR compressors.

The South Yard Flare System is connected to relief systems from process units located in the Distillation & Reforming (D&R) Area Business Unit (ABU), the Utilities & Environmental (U&E) ABU and the Blending & Shipping (B&S) ABU. There are two flares connected to the South Yard system. These flares, and the process units associated with them, are listed in Table 2-3.

Table 2-3 South Yard Flare System Plant Sources

<i>BAAD Flare No.</i>	<i>Flare Name</i>	<i>Process Units</i>
S-6010	LSFO	S-4226, FCC Gas Hydrotreater (FCC GHT) S-4233, Jet Hydrotreater (JHT) S-4234, #5 Naphtha Hydrotreater (5NHT) S-4235, Diesel Hydrotreater (DHT) S-4236, #4 Crude Unit (4CU) S-4282, Penhex Isomerization Unit (Penhex) S-4283, #4 Rheniformer (4CAT) S-4237, #5 Rheniformer (5CAT) S-4435, #5 H2S Plant (5H2S) Cogeneration Plant Sources Utilities Plant Sources Hydrogen Plant Liquid Knockouts
S-6015	D&R	S-4226, FCC Gas Hydrotreater (FCC GHT) S-4233, Jet Hydrotreater (JHT) S-4234, #5 Naphtha Hydrotreater (5NHT) S-4235, Diesel Hydrotreater (DHT) S-4236, #4 Crude Unit (4CU) S-4282, Penhex Isomerization Unit (Penhex)

<i>BAAD Flare No.</i>	<i>Flare Name</i>	<i>Process Units</i>
		S-4283, #4 Rheniformer (4CAT) S-4237, #5 Rheniformer (5CAT) S-4435, #5 H2S Plant (5H2S) Cogeneration Plant Sources Utilities Plant Sources

Hydrogen Plant

The Hydrogen Plant flare has no routine flaring and is operated primarily for safety reasons. The flare at the Hydrogen Plant is operated in a manner consistent with permit condition 28 in the Authority to Construct permit for the Hydrogen Plant issued by BAAD and this plan. The flare is a steam assisted, elevated flare and is maintained by flare pilots, which are fired by natural gas. The pilot flame and sweep gas operate at all times.

The primary gases combusted in the Hydrogen Plant flare are comprised of hydrogen, methane, carbon dioxide and carbon monoxide. In addition, very small volumes of ammonia may be flared from ammonia processing equipment. For the primary gases, the flare may operate for the following scenarios in addition to startup, shutdown, emergency upset and breakdown:

1. **The loss of hydrogen purity due to feedstock variability (e.g. high nitrogen in the natural gas).** During this event, the product hydrogen may be out of required specifications, potentially causing a problem for the downstream users of hydrogen. Gas may need to be flared until the problem is corrected. See Section 5.2 for more details.
2. **Loss of a PSA bed on PSA1 or PSA2 due to an automatic valve malfunction.** Valve malfunctions on the PSA are occasional occurrences due to the number of valves (72 automatic valves on PSA1 alone) and their cyclical service. The valves cycle every few minutes. The malfunction of a PSA automatic valve can cause a PSA bed to be taken out of service. This, in turn, increases the PSA tail gas flow. Depending on the dynamics of the increase of PSA tail gas flow, it may not always be possible to immediately send the additional flow to the hydrogen plant furnace without overheating the furnace. Eventually, the natural gas is backed down to make room for the additional PSA tail gas flow. But in the meantime, flaring can occur during this disturbance.

Two key events can cause the loss of hydrogen purity from the PSA: (1) variability in the PSA feed concentration and (2) high tail gas pressure. The malfunction of a PSA automatic valve increases the tail gas flow. Sending this additional flow to the furnace increases the furnace temperature, which increases the reaction temperature on the process side, which changes the PSA feed composition. Therefore, changes in tail gas flow to the furnace must be made in a relatively slow, controlled fashion to maintain constant furnace temperature. The other option is to maintain constant tail gas flow and let the pressure build within the PSA tail gas surge tank. Unfortunately, the pressure builds quickly and above 6 psig, a loss of hydrogen purity can occur. As a result, the predominant strategy in the industry is to temporarily vent the additional tail gas to the flare when the pressure in the surge tank reaches 6 psig. Ultimately, the tail gas flow is increased to the furnace and the flaring of the tail gas ceases. The flaring in this scenario may lead to a flaring event as defined in Regulation 12-12-208. The

estimated flaring from the loss of a PSA automatic valve is 1,000,000 cubic feet per hour. The actual flaring amount may be more or less depending on the circumstances. The flaring event duration is anticipated to be less than two hours. It should also be noted that the pressure set point of 6 psig is not applicable during startup. The tail gas is often flared at a lower pressure during a startup to decrease the time it takes to achieve hydrogen product purity.

3. **Sudden change in hydrogen demand.** Under normal circumstances, a reduction in hydrogen demand will be anticipated and coordinated ahead of time. In this way, production can be reduced prior to the reduction in demand to avoid venting to the flare. It is only under circumstances that are “unplanned” and “beyond reasonable control” that the reduction in hydrogen demand can lead to flaring. Each reformer furnace is able to adjust production without flaring at a rate of 1% capacity every 7 minutes. This translates into a change of 1.15 MMSCFD of hydrogen production every 7 minutes. Reductions in the hydrogen demand at a rate greater than 1.15 MMSCFD every 7 minutes can lead to temporarily routing hydrogen product to the flare until the plant rate can be brought in line. Depending on the magnitude of change, this may lead to a flaring event as defined in Regulation 12-12-208.
4. **Purging to prepare equipment for maintenance.** In order to safely do maintenance on a piece of equipment, it must be purged to achieve a safe atmosphere.

The equipment is isolated, depressurized, inerted with nitrogen, repaired, and brought back online. If the piece of equipment can be taken down with the remainder of the plant running, gas upstream of the equipment is not vented to the flare. The amount of flaring is small during these events, normally below 50,000 cubic feet/event. It may not be possible to send gas to the furnace in a maintenance situation, as the furnace may not be operational. Preparing equipment for maintenance can typically be done without triggering a flaring event as defined in Regulation 12-12-208. It is estimated that preparing equipment for maintenance may occur several times per year.

Under rare circumstances, refinery process gas (RPG) may be sent to the Hydrogen Plant flare. There are four identified scenarios under which RPG could be flared in the Hydrogen Plant flare.

1. **Compressor tail gas malfunction or shutdown.** There are three compressors that handle RPG. In the event of a sudden malfunction or shutdown of the tail gas portion of one of the compressors, independent of the rest of the compressor, RPG could be vented to the flare while the shutdown process occurs.
2. **Maintenance of the Hydrogen Plant's RPG system.** Flaring may occur during isolation, depressurization, and inerting with nitrogen of the Hydrogen Plant's RPG piping system and vessels for maintenance (flaring prior to implementation of bypass of PSA system). This depressurization would take place through existing flare connections in the Hydrogen Recovery Unit (PSA3) unit. Once repaired it will be brought back online. If the piece of equipment can be taken down with the remainder of the plant running, the gas upstream of the equipment is not flared. The amount of flaring is expected to be small during these events, normally below 50,000 cubic feet/event. It may not be possible to send gas to a furnace in a maintenance situation, as the furnace may not be operational. Preparing equipment for maintenance can typically be done without triggering a flaring event as defined in Regulation 12-12-208. It is estimated that preparing equipment containing RPG for maintenance may occur two to three times per year.
3. **Loss of a PSA bed on Hydrogen Recovery Unit due to an automatic valve malfunction.** This is similar to an automatic valve malfunction on PSA1 or PSA2.

There are 48 automatic valves on the Hydrogen Recovery Unit and they operate in cyclical service. The valves cycle every few minutes. The malfunction of a PSA automatic valve can cause a PSA bed to be taken out of service. This, in turn, increases the PSA tail gas flow. In almost all scenarios, the tail gas compressor will be able to process the additional tail gas flow. In rare circumstances the dynamics of the increase of PSA tail gas flow may cause the pressure in the Hydrogen Recovery Unit tail gas surge tank to rise to 6 psig. At 6 psig, a loss of hydrogen purity can occur, which can lead to a greater volume of gas being sent to the flare and an increased probability of a flaring event as defined in Regulation 12-12-208. As a result, the predominant strategy in the industry is to temporarily send the additional tail gas to the flare when the pressure in the surge tank reaches 6 psig.

As the tail gas compressor is able to absorb changes in tail gas flow more easily than a SMR furnace, the likelihood of a flaring event as defined in Regulation 12-12-208 is greatly reduced. It is anticipated that the flaring event duration will be less than one hour and occur infrequently. The maximum flaring from the loss of a Hydrogen Recovery Unit automatic valve is still 1,000,000 cubic feet per hour. The actual flaring amount may be more or less depending on the circumstances.

4. **Compressor seal leakage into the nitrogen purge flow.** For safety reasons, gas would be flared in the event of compressor seal leakage into the nitrogen purge flow. As the flare is at an elevation of 195 feet, this allows the gas to be combusted at a height safely above any personnel. To send this gas to any device at a height less than 195 feet high potentially exposes personnel to radiation or flammable gas hazards. The estimated vent gas flow for a total compressor seal failure is 11,600,000 cubic feet/day. The compressor will be shut down immediately on a total compressor seal failure.

A “telltale” has been installed on each seal system at the Hydrogen Plant that provides an alert prior to a total compressor seal failure. There is a temperature measurement on each “telltale”, with high alarm, in the Control System. The amount of gas sent to the flare from the “telltale” will not generate a flaring event. Upon detection of a high temperature alarm, provisions will be made to take the affected compressor out of service and the seal fixed.

These scenarios are discussed in more detail in sections 5.1.1 and 5.1.3.

A Simplified Flow Diagram for the flare system is included in Appendix A to this document. Please note the following in relation to this flow diagram:

- Sources used during non-emergency/malfunction/upset/contractual outage/customer constraint/maintenance flaring, such as during startup and shutdown, are as follows: PSA1 and Train 1 Hydrogen-Rich Knockout Drum (D-1240) (associated with Hydrogen Plant Train 1, S-4449); PSA2 and Train 2 Hydrogen-Rich Knockout Drum (D-2240) (associated with Hydrogen Plant Train 2, S-4450); and Hydrogen Recovery Unit (S-4451).
- All gases enter the flare header upstream of the flow meters and are measured.

The sources of vent and purge gases that could be flared are listed in Table 2-4.

Table 2-4 Hydrogen Plant Flare System Sources

BAAD Flare No.	Process Units
S-6021	<i>Sources flaring only during emergency upset, sudden hydrogen demand change, or maintenance conditions:</i> Relief valves in the feed gas separator drums Pressure Swing Adsorption 3 (Hydrogen Recovery Unit) area safety valves Relief valves in the feed gas pretreatment to the SMRs Relief valves in the hydrogen rich gas system downstream of the SMRs NG fuel relief protection SCR system relief protection PSA1 and PSA2 area safety valves Feed gas compressors Analyzer buildings 1 and 2 Oil removal skid
	<i>Sources flaring in non-emergency events (e.g. start-up, shut-down):</i> Hydrogen rich gas automatic vent before the PSA1 (S-4449) and PSA2 (S-4450) units. PSA1 (S-4449) and PSA2 (S-4450) startup flaring Hydrogen Recovery Unit (S-4451) startup flaring

2.2 Detailed Diagrams for Flaring Systems

Table 2-5 provides a list of Piping & Instrumentation Diagrams (P&IDs) for each of the refinery's currently regulated flares. Copies of the P&IDs are located in Appendix B to this document. Drawings were updated reflecting a September 2025 North Isomax functionally identical flare tip replacement. The replaced flare tip is functionally identical to the previous flare tip in terms of the maximum relief rate, natural gas purge rate, flare pilot natural gas rating, and routine steam flow rate¹.

Table 2-5 Flare P&IDs (refer to Appendix B)

Drawing No.	Drawing Version	Flare or Flare System
D-313651-22C-3	"Design"	LSFO Flare
D-313651-22C-REM-1	"Design"	LSFO Flare
D-320896-23D-2	"Design"	Alky Flare
D-320896-23D-REM-2	"Design"	Alky Flare

¹ Both the previous and replacement flare tip maximum relief rates are 996,000 pounds per hour (pph). The previous tip's purge gas rate is 1,500 standard cubic feet of natural gas per hour (scfh) and the replacement tip's purge gas rate is 1,490 scfh. The previous tip's pilots were rated at 75 scfh at 25 pounds per square inch gauge (psig) and the replacement tip's pilots are rated at 65 scfh at 15 psig. The previous tip's routine steam flow rate is 1,380 pph and the replacement tip's routine steam flow rate is 1,310 pph.

D-320897	"Design"	FCC Flare
D-320897-29	"Design"	FCC Flare
D-324787-34C-2	"Design"	RLOP Flare
D-324787-34C-REM-2	"Design"	RLOP Flare
D-324793-33	"Design"	North Isomax Flare
SE-6442-S1-2R7	"Design"	North Isomax Flare Tip
D-324793-23C-REM-2	"Design"	North Isomax Flare
D-324795-25B-2	"Design"	South Isomax Flare
D-324795-25B-REM-1	"Design"	South Isomax Flare
D-329038-16B-1	"Design"	D&R Flare
D-329038-16B-REM-1	"Design"	D&R Flare

Table 2-6 provides a list of mechanical elevation drawings for each currently regulated flare. Copies of the drawings are located in Appendix C to this document.

Table 2-6 Flare Elevation Drawings (refer to Appendix C)

<i>Chevron Drawing No. (Vendor No., if other)</i>	<i>Drawing Version</i>	<i>Flare or Flare System</i>
146216-2-F-2 (259-A-EWS-1)	Revision 1	FCC Flare (S-6016)
14216-2-F-2 (262-A-EWS-1)	Revision 3	Alky-Poly Flare (S-6019)
14216-2-F-4 (301-A-EWS-1)	Revision 2	RLOP Flare (S-6139)
14216-2-F-2 (244-A-EWS-1)	Revision 4	NISO Flare (S-6013)
FP-202318-0 (F92-0726-301)	Revision 2	SISO Flare (S-6012)
A-160960-8	Revision 8	SISO Flare (S-6012)
10640-2-F-40 (B-F-069761-302)	Revision 3	LSFO Flare (S-6010)
D-229930-0	Revision 0	LSFO Flare (S-6010)
D-228265-0	Revision 0	LSFO Flare (S-6010)
FP-207308 (B-F-913483-202)	Revision 6	D&R Flare (S-6015)

<i>Chevron Drawing No. (Vendor No., if other)</i>	<i>Drawing Version</i>	<i>Flare or Flare System</i>
DF-9013917-201	Revision 3	H2 Plant Flare (S-6021)

2.3 Monitoring and Control Equipment

2.3.1 Flare Gas Flow Monitoring

As required by BAAD Regulation 12 Rule 11, Section 501 and to meet the accuracy requirements of 40 CFR 63 Subpart CC, all of the refinery's current active flares are equipped with continuous flare vent gas flow meters. The flow meters currently used for this monitoring are listed in Table 2-7a and contain multiple outputs as shown. Flowmeters are shown Table 2-7a. The flow meters are located upstream of each flare and downstream of any piping connections to the relief header.

Table 2-7a Flare System Flowmeters

<i>Tag Numbers</i>	<i>Name & Location</i>	<i>Type</i>	<i>Ranges</i>
59FI735 59PI735 59TI735 59AI735	<u>FCC Flare vent gas flowmeter</u> Installed between the flare sub-header line and the inlet to FCC Flare (S-6016). P&ID D-387636	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol
59FI737 59PI737 59TI737 59AI737	<u>FCC Flare vent gas flowmeter</u> Installed between the flare sub-header line and the inlet to FCC Flare (S-6016). P&ID D-387635	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol
59FI736 59PI736 59TI736 59AI736	<u>Alky-Poly Flare vent gas flowmeter</u> Installed on Cracking Area relief line, between connection to FCC flare vent gas line and inlet to Alky-Poly Flare (S-6019). P&ID D-387639	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol
80FI110 80PI110 80TI110 80AI110	<u>RLOP Flare vent gas flowmeter</u> Installed on RLOP Area relief line, between connection to North Yard FGR System and inlet to RLOP Flare (S-6039). P&ID D-387621	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol
69FI287 69PI287 69TI287 69AI287	<u>NISO Flare vent gas flowmeter</u> Installed on North Isomax Area relief line, between connection to North Yard FGR System and inlet to NISO Flare (S-6013). P&ID D-387630	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol

<i>Tag Numbers</i>	<i>Name & Location</i>	<i>Type</i>	<i>Ranges</i>
69FI286 69PI286 69TI286 69AI286	<u>SISO Flare vent gas flowmeter</u> Installed on South Isomax Area relief line, between connection to North Yard FGR System and inlet to SISO Flare (S-6012). P&ID D-387633	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol
39FI002 39PI002 39TI002 39AI002	<u>LSFO Flare vent gas flowmeter</u> Installed on D&R ABU relief line, between connection to South Yard FGR System and inlet to LSFO Flare (S-6010). P&ID D-387624	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol
39FI030 39PI030 39TI030 39AI030	<u>D&R Flare vent gas flowmeter</u> Installed on D&R ABU relief line, between connection to South Yard FGR System and inlet to D&R Flare (S-6015). P&ID D-387627	gas ultrasonic flowmeter	-10 to 300 MMSCFD 13.8 to 43.6 PSIA 0 to 800 °F 2 to 120 Gram/mol
31FI34011 31PI34011 31TI34011 31AI34011	<u>H2 Plant Flare Train 1 vent gas flow meter</u> Installed between flare sub-header line and inlet to Hydrogen Plant Flare (S-6021). P&ID D-383461	gas ultrasonic flowmeter	0 to 200 MMSCFD 14.7 to 29.7 PSIA 0 to 302 °F
31FI34012 31PI34012 31TI34012 31AI34012	<u>H2 Plant Flare Train 2 vent gas flow meter</u> Installed between flare sub-header line and inlet to Hydrogen Plant Flare (S-6021). P&ID D-383461	gas ultrasonic flowmeter	0 to 200 MMSCFD 14.7 to 29.7 PSIA 0 to 302 °F
31FI34017 31PI34017 31TI34017 31AI34017	<u>H2 Plant Flare Ammonia vent gas flow meter</u> Installed in flare sub-header and inlet to Hydrogen Plant Flare (S-6021) P&ID D-383570	gas ultrasonic flowmeter	0 to 1.5 MMSCFD 14.7 to 24.7 PSIA 0 to 200 °F

2.3.2 Water Seal Integrity & Pressure Monitoring

As required by BAAD Regulation 12, Rule 12, Section 501, “the owner or operator of a flare subject to this rule with a water seal shall continuously monitor and record the water level and pressure of the water seal that services each flare.” The North Yard and South Yard flares are each equipped with a water seal. The refinery maintains and operates instrumentation to continuously monitor and record the flare header pressure and the water seal liquid level for each flare. The integrity of each water seal is ensured during any period where the liquid level in the water seal, measured in units of inches of water by a liquid level transmitter, exceeds the flare header pressure, measured in terms of inches of water by a pressure transmitter. A “reportable flaring event,” as defined in Reg. 12-12-208, ends “when it can be demonstrated by

monitoring required in Section 12-12-501 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip.” Flaring, as defined in Reg. 12-12-203, can only occur when the integrity of the water seal has been compromised, as indicated when the flare header pressure in terms of inches of water exceeds the water seal liquid level (inches). The liquid level and pressure transmitters used for flare relief header pressure and water seal liquid level monitoring are listed in Table 2-8.

Liquid Level Monitoring – The water seals on the North Yard flares are replenished on continuous overflow using stripped sour water supplied from the stripped water tank T-3340. Each water seal is equipped with a continuous overflow of water. The system is designed in keeping with manufacturer recommendations to remove or “skim” hydrocarbons off the top of the water seal. Liquid hydrocarbons in the seal can inhibit the accuracy of liquid level transmitters and can create unsafe conditions during flaring events. Spent water then gravity feeds to V-283 rundown vessel for the North Yard flare water seals. V-283 is maintained at atmospheric pressure, with an equalization line between V-283 and the North Isomax flare stack. Any hydrocarbon compounds that could be present in V-283 are from flare rundown and therefore would have already been monitored by one of the five North Yard flare meters. The South Yard flares water seals are replenished using fresh water via an automated level control valve to maintain the designated seal level. Spent water is then routed to the water-oil separator. Water seal liquid level transmitters for currently active flares in the North Yard and South Yard are calibrated to read “0 inches” at the water level equivalent to zero effective inches of water seal.

Pressure Monitoring – The relief header pressure is measured by pressure transmitters associated with the ultrasonic flow meter installations described in Section 2.3.1. Relief header pressure and temperature are used to convert actual flow rate measurement to engineering unit flow rates at standard temperature and pressure. The relief header pressure transmitters are located in the flare vent gas lines upstream of each flare connection to provide a measurement of the gauge line pressure (relative to atmospheric pressure) on the vent gas line side of the water seal.

Table 2-8 Water Seal Level Indicators and Flare Vent Gas Pressure

<i>Tag Number</i>	<i>Instrument (P&ID #)</i>	<i>Instrument Type</i>	<i>Range</i>
59LI731A	FCC Flare water seal level height, in inches P&ID D-320897	Differential Pressure Level Transmitter	-10 to +43 inches water column
59PI735 59PI737	FCC Flare vent gas pressure P&ID D-320897	Honeywell Pressure Transmitter, absolute pressure	13.8 to 43.6 PSIA
59LI732A	Alky-Poly Flare water seal level indicator. P&ID D-320896	Differential Pressure Level Transmitter	-64 to +56 inches water column
59PI736	Alky-Poly Flare vent gas pressure P&ID D-320896	Honeywell Pressure Transmitter, absolute pressure	13.8 to 43.6 PSIA
80LI501A	RLOP Flare water seal level P&ID D-324787	Guided wave radar level transmitter	-5 to +62 inches water column

80PI110	RLOP Flare vent gas pressure P&ID D-324787	Honeywell Pressure Transmitter, absolute pressure	13.8 to 43.6 PSIA
69LI281A	NISO Flare water seal level indicator. P&ID D-324793.	Guided wave radar level transmitter	-7 to +72 inches water column
69PI287	NISO Flare vent gas pressure P&ID D-324793	Honeywell Pressure Transmitter, absolute pressure	13.8 to 43.6 PSIA
69LI282A	SISO Flare water seal level indicator. P&ID D-324795	Guided wave radar level transmitter	-8.5 to +56.5 inches water column
69PI286	SISO Flare vent gas pressure P&ID D-324795	Honeywell Pressure Transmitter, absolute pressure	13.8 to 43.6 PSIA
39LC003	LSFO Flare water seal level indicator. P&ID D-313651	Displacer Type Transmitter	0 to 37 inches water column
39PI002	LSFO Flare vent gas pressure P&ID D-313651	Honeywell Pressure Transmitter, absolute pressure	13.8 to 43.6 PSIA
39LC030 39LT031	D&R Flare water seal level transmitter. P&ID D-329038	Displacer Type Transmitter	-25 to 450 inches water column
39PI030	D&R Flare vent gas pressure P&ID D-368506	Honeywell Pressure Transmitter, absolute pressure	13.8 to 43.6 PSIA

Water seals were considered in the design of the Hydrogen Plant since, if placed in the correct location, these could serve to differentiate low flow 'noise' from actual flow. However, water seals are not used at the Hydrogen Plant due the backpressure they exert which could negatively affect process operations. There are several Pressure Safety Valves (PSVs) that have low set pressures. Adding any more backpressure to the outlet of these PSV's was determined to not be a good safety practice.

2.3.3 Flare Gas Continuous Recording Instruments

All flares are equipped with a mass spectrometer to monitor vent gas composition. The mass spectrometers are Extrel MAX300-IGs. The mass spectrometers monitor components including hydrogen, lower heating value, and hydrogen sulfide. The mass spectrometer is dedicated to monitor vent gas, removing the need to pull samples in the event of flaring. Eight mass spectrometers are installed such that the vent gas for each flare is analyzed by a mass spectrometer.

3.0 Past Reductions

Pursuant to the requirements of Regulation 12, Rule 12, Section 401.2, this section provides a description of equipment, processes or procedures that the Richmond Refinery installed or

implemented to reduce flaring during the five years immediately preceding promulgation of Regulation 12, Rule 12 (on July 20, 2005). Past changes, and the year in which they were implemented, are summarized below in Table 3-1.

The listing of historical changes provided in Table 3-1 is intended as a one-time snapshot of Chevron's good faith efforts to reduce flaring prior to the implementation of Regulation 12, Rule 12. Past changes, and the year in which they were implemented, are also summarized below.

Table 3-1 Historical Changes to Reduce Flaring

<i>Year Installed or Implemented</i>	<i>Flare System Affected</i>	<i>Equipment Item Added, Process Changed or Procedure Implemented</i>
2000	South Yard	Started placing crude unit vent gas recovery compressors in service as FGR compressors (when K-3950 FGR compressor output is down or limited) depending on availability. Either K-1171, K-1171A, or both are put in service using a manual procedure in the field. K-1171 and K-1171A can provide 1.7MMSCFD capacity apiece in combined FGR / process service. The additional FGR capacity provided by K-1171 and K-1171A reduces flaring by increasing the ability of the South Yard FGR system to recover all relief gas when K-3950 output is down or limited. (There is no benefit to running the spare compressors as long as the FGR load does not exceed the capacity of the current FGR compressors.) K-1171 and K-1171A are two-stage, Ingersoll-Rand model 2HSE2 25X14.5X9 reciprocating units.
2002	All	Shutdown Flare Planning Process implemented for planned maintenance work during plant shutdowns (i.e., turnarounds) (See section 5.1.6).
2002	South Yard	Implemented source control to reduce relief gas flows into the South Yard Flare Gas Recovery system. The source control effort was an intensive look that was undertaken to identify sources of loading to the South Yard Flare Gas Recovery system, such as valves, vents and pressure relief devices. Identifying and controlling these sources reduced the overall load on the FGR system. The likelihood of flaring was reduced because the FGR compressors would be more likely to recover all of the flare gas generated.
2002/2003	all	The "Fuel Gas Load Shed" procedure worksheet was revised. This procedure provides a series of operational steps to respond to situations where the fuel gas demand begins to dip, or when fuel gas production exceeds demand, and excess relief gas generation could eventually cause flaring, by reducing the load on the FGR system. This worksheet provides a sequence of steps that reduce process gas generation and/or create more uses for fuel gases generated. The Refinery Shift Coordinator monitors natural gas makeup to the fuel gas drums. If this make-up drops, it indicates that the fuel balance is approaching the point at which more gas could be produced than could be consumed. The Fuel Gas Load Shed procedure is implemented to provide a "cushion" to avoid situations causing flaring because there is more fuel gas produced than can be

<i>Year Installed or Implemented</i>	<i>Flare System Affected</i>	<i>Equipment Item Added, Process Changed or Procedure Implemented</i>
		<p>consumed. Some steps are taken to reduce the load on the fuel gas system by creating more fuel gas consumers, for example as switching electric drivers to steam turbines, and increasing cold feed into units (which would require fuel gas consumption to heat up the feed). Some steps are taken to reduce the load on the fuel gas system by reducing the amount of gas generated, for example employing secondary cooling to increase heat transfer and condense more material in overhead systems; backwashing heat exchangers to increase their heat transfer, provide better cooling and reduce vent gas generation; raising process column pressures, which reduces the gas make-up required; and raising the LPG content of the gasoline streams.</p> <p>Curtailing refinery operations also reduces the load on the fuel gas system by reducing the amount of gas generated, such as stopping the offloading of LPG cars, reducing unit operating severity to reduce the amount of gas generated, and reducing unit throughputs to reduce gas make-up. This worksheet has been continually updated over the past twenty years as improvements are identified. The Fuel Gas Load Shed procedure is employed to respond to plant conditions which could cause a fuel gas imbalance. The response to any particular event is dependent on the operating conditions at the time and the exact cause of the FGR system reaching full capacity. In different scenarios some actions are more effective than others. This is not the optimal or even desirable mode of operations in most circumstances, as overall facility efficiency is reduced and facility emissions may increase. (When shutting down plants for maintenance, fuel gas load is not the issue, as more sources of fuel gas generation than fuel gas consumers are lost, so the Fuel Gas Load Shed procedure is not needed for planned shutdowns. Flaring that occurs during the planned shutdown process is due to the inability to stay on FGR while depressuring and purging equipment, rather than any fuel gas balance issues.)</p>
2003	North Yard	Temporary scrubber: A spare scrubber unit was employed during the 1Q2003 RLOP shutdown so C-890 scrubber could undergo maintenance without interruption of scrubber operation. By maintaining this scrubbing capacity, this gas stream could be recovered instead of having to be flared. The spare was removed after maintenance was completed. During normal operation there is sufficient scrubbing capacity, so portable scrubbing units are generally not required.
2003 – 2005	North Yard	K-1060 and K-1070 North Yard flare gas recovery compressors (Worthington, two stage, three cylinder, reciprocating) had modifications to internal parts and auxiliary systems to increase reliability and potential ability to handle gases with higher heats of compression (e.g., Nitrogen, Hydrogen). Internal modifications included material upgrades to piston parts. The

<i>Year Installed or Implemented</i>	<i>Flare System Affected</i>	<i>Equipment Item Added, Process Changed or Procedure Implemented</i>
		internal modifications were completed in several stages, incorporating lessons learned to allow for a slight increase in operating temperature, which would enable plants to stay on FGR for a longer period of time during some clean-up operations. Modifications to auxiliary systems included adding a spare pump to the FGR compressor knockout drum to reduce the chance of the system shutdown, and adding supplemental cooling to a relief drum to enhance gas recovery. The higher discharge temperature for K-1060 and K-1070 and measures to increase reliability will directionally allow plants to remain on FGR for longer periods during shutdown purge and cleanup operations, and start-up activities.
2003	North Yard	Source control: Installed 15 Kurz Model 454 FT thermal convection mass flow indicators on relief lines to provide better indication of source of relief gases. The source control effort was an intensive look that was undertaken to identify sources of loading to the North Yard Flare Gas Recovery system, such as valves, vents and pressure relief devices. The flow meters were installed to help identify these sources so they could be controlled. Controlling these sources reduced the overall load on the FGR system. The likelihood of flaring was reduced because the FGR compressors would be more likely to recover all of the flare gas generated.
2003-2004	all	The E-1190 fogger capital project provided supplemental cooling to the overhead of the C-1190 Naphtha Stabilizer column in the Crude unit when ambient temperatures are expected to exceed 75 F. Cleaning fin fan heat exchangers for the summer months also provides greater cooling efficiency. Both of these reduce the generation of vent gases which would otherwise add to the load on the FGR systems. Reducing the load on FGR systems reduces the likelihood of flaring because the FGR compressors would be more likely to recover all of the flare gas generated. New operating procedures 4CU4765j, 4CU4770j, and 4CU4775j were implemented for operation of the E-1190 fogger. Operating procedure 4CU-NP-4780 was implemented for fin fan cleaning. These procedures are implemented when ambient temperatures are expected to exceed 75 F, as described above.
2003 - 2004	North Yard	K-400/K-500 plant recycle compressor replacement. Prior to replacing the recycle compressors, there were several unplanned shutdowns of K-400 and K-500, which in turn caused their respective TKC and TKN units to shutdown. Unplanned unit shutdowns required rapid depressuring of equipment which caused flaring. Replacing the recycle compressors improved their reliability, thereby avoiding unplanned shutdowns and flaring.
September 2007	Both	Flare source and meter database: Databases and tools have been developed to track sources by business locations,

<i>Year Installed or Implemented</i>	<i>Flare System Affected</i>	<i>Equipment Item Added, Process Changed or Procedure Implemented</i>
		operation activities (shutdowns), valve types, and by dates when leaks are identified and fixed. They can also assist operation staff to make any necessary operational moves to minimize potential flaring.
July to December 2007	Both	Multiple training sessions were conducted with operation staff to communicate the requirement of the FMP.
December, 2007	South Yard	A new ¾" bypass valve was installed at Cogen's LPG knock-out drum in addition to its original 2" valve to enhance the control of blowdown rate.
January, 2008	Both	All drain and vent valves routed to FGR systems were labeled to advise caution while being operated. Identifying all valved sources to FGR systems will reduce loading on FGR compressors.
DHT Maintenance Event 2008	South Yard	A steam condenser was designed and installed to reduce loading on the relief system during steam cleaning of the process equipment. Use of a temporary condenser will be considered in future DHT turnaround events in order to minimize the amount of steam that flows to the relief header.
December 2007, April 2008	Both	December 2007: A temporary back-up generator was installed. April 2008: A permanent back-up diesel generator has been added to the 5 H2S Emergency Scrubber C-840. The existing C-840 emergency scrubber prevents the burning of H2S in the flare by absorbing the H2S in an aqueous ammonia solution. A permanent back-up diesel generator was permitted, installed, and commissioned into service in 2008. This addition will not alter 5 H2S or C-840 operations. Instead, it will ensure continuous circulation of the scrubbing solution during an unexpected power outage and therefore maintain decreased H2S concentrations.
RLOP Area Turnaround 2009	North Yard	During the 2009 turnaround of the RLOP area, a cooldown process using recycle gas instead of NiCool to cool reactor vessels was tested. The goal of this cleanup technique was to reduce load on the FGR compressors. This practice may be used during future turnarounds.
4CU Pitstop Maintenance 2009	South Yard	The 4CU Process Unit and several associated process plants in the Distillation and Reforming area will consider implementing the following practices to minimizing flaring during planned maintenance; de-pressure to relief at a slower rate per revised procedures and depressuring DHT to a downstream process unit to a lower pressure target before sending material to relief. Operations implemented the identified flare minimization measures during a 2009 turnaround, and will consider implementing these practices in future turnarounds.

<i>Year Installed or Implemented</i>	<i>Flare System Affected</i>	<i>Equipment Item Added, Process Changed or Procedure Implemented</i>
October 10, 2010	North Yard	Flare Minimization Planning for FCC Complex Turnaround. The FCC operating area is employing condensing systems to assist with flare minimization during its 2010 turnaround.
March 14, 2011	North Yard	Upgrade the North Yard FGR compressor's common electrical power supply system to separate feeders so that when one FGR compressor is shut down for maintenance, the other FGR compressor will be in service.
October 4, 2011	North Yard	Flare Minimization Planning for RLOP Complex Turnaround The RLOP operating area is employing condensing systems to assist with flare minimization during its 2011 turnaround. A steam condenser was designed and installed to reduce loading on the relief system during steam cleaning of the process equipment.
October 6, 2011	South Yard	Flare Minimization Planning for D&R Complex Turnaround. The D&R ABU is employing condensing systems to assist with flare minimization during its 2011 turnaround. A steam condenser was designed and installed to reduce loading on the relief system during steam cleaning of the process equipment.
November 2012	North Yard	Upgrade the North Yard FGR compressors (K-1060 and K-1070) with unloader valve replacements and replace K-1070 structural frame in order to improve the reliability.
March, 2013	South Yard	Operation of the flares in a staged basis. The LSFO Flare (S-6010) and D&R Flare (S-6015) will operate on a staged basis. Under normal conditions, the D&R Flare will only operate once the LSFO Flare approaches its smokeless capacity. Flaring through the D&R Flare will therefore be minimized as specified in Condition No. 24921, Part 2. The LSFO Flare will remain the primary flare during any process unit startup or shutdown activities. When the LSFO Flare is out of service for maintenance, the D&R Flare will operate as the primary South Yard flare. When the D&R Flare serves as the only South Yard flare, the water seal level will remain set at a level higher than that of the LSFO Flare in order to further minimize flaring and maximize flare gas recovery and maintain safe operation.
October 2015	North Yard	Flare Minimization Planning for FCC Complex Turnaround. The FCC operating area is employing condensing systems to assist with flare minimization during its 2015 turnaround.
June 2019	North Yard	Install and place a new emergency caustic scrubber (C-2440) in service. To prevent or minimize burning of H ₂ S in the flare system, a new emergency caustic scrubber (C-2440) has been installed for removal of H ₂ S from acid gases prior to routing to the relief system.
October 2020	North Yard	Flare Minimization Planning for FCC Complex Turnaround. The FCC operating area is employing condensing systems to assist with flare minimization during its 2020 turnaround.

<i>Year Installed or Implemented</i>	<i>Flare System Affected</i>	<i>Equipment Item Added, Process Changed or Procedure Implemented</i>
June 2022	North Yard	Flare Minimization Planning for RLOP Turnaround. The RLOP operating area employed condensing systems to assist with flare minimization during its 2022 turnaround. They also routed offgas from TKN GRU to minimize the FGR load, and ensured both FGR compressors were online to maximize FGR capacity.

4.0 Planned (Future) Reductions

Pursuant to the requirements of Regulation 12, Rule 12, Section 401.3, and 401.4.1 and 401.4.2 (feasible prevention measures) this section provides descriptions of any equipment, processes or procedures that the Richmond Refinery plans to install or implement to eliminate or reduce flaring.

Table 4-1 below summarizes planned improvements to effect further reductions in refinery flaring. The procedural changes described below require a year in order to optimize the improvements, update tools and communicate and train employees. The planned dates shown are driven by equipment installation and procedural changes that take advantage of the equipment.

Causal analyses of flaring events identified actions to maintain plant reliability that would reduce the likelihood of incidents which could cause potential flaring. These actions included the inspection and repair of equipment components that were either implemented as part of normal operations, or were scheduled for the next plant turnaround as described in Section 5.1.6 and Figure 5-1. Other actions are included in Table 4-1 below.

Table 4-1 includes measures considered to reduce flaring from planned major maintenance activities. There were no measures identified that were considered and rejected. Table 4-1 also includes measures considered to reduce flaring that may occur because of issues of flare gas quality and quantity. Measures that were considered but rejected are described in sections 5.2.4 and 5.2.5, including Table 5-3, under options considered for additional flare gas recovery, treatment, or use.

There were no other improvements considered that were not either included in Sections 5.2.4 and 5.2.5, or included in Table 4-1.

Table 4-1 Planned Improvements to Reduce Flaring

<i>Planned Date of Installation/ Implementation</i>	<i>Equipment Item to be Added, Process to be Changed or Procedure to be Implemented</i>	<i>Flare System Affected</i>	<i>Notes</i>
May 2007 – On Going	Source reduction	Both	The source control program continues as an on-going function at the Refinery. In 2008, several source control actions were taken, including repairing V-910, V-920, and V-930 bypasses in the Hydrogen Manufacturing Plant and replacing two blowdown valves on V-2010 that are leaking

<i>Planned Date of Installation/ Implementation</i>	<i>Equipment Item to be Added, Process to be Changed or Procedure to be Implemented</i>	<i>Flare System Affected</i>	<i>Notes</i>
			by to relief. In 2014, valves associated with V-1600 in D&R were replaced during a shutdown due to leaks into the relief system.
January 2008 – On Going	Infrared (I.R.) camera has been used as a predictive maintenance tool.	Both	After a major overhaul, FGR compressors are inspected using the I.R. camera to evaluate compressor performance and to predict if maintenance is needed.
July 2007 – On Going	Site-wide flare minimization team	Both	A multidisciplinary team focused on flare minimization meets monthly to address the refinery's flare minimization issues. The team is made up of operations, process engineering, and environmental personnel. These meetings continue and action items are identified, considered, and implemented on an on-going basis throughout the year.

5.0 Prevention Measures

5.1 Major Maintenance Activities

Pursuant to the requirements of Regulation 12, Rule 12, Section 401.4.1, this section discusses refinery maintenance and turnaround activities and outlines measures to minimize flaring during planned and unplanned maintenance activities. The section includes information on when flaring is likely to occur during maintenance activities, comments on the effects of recovered flare gas on downstream equipment, a review of flaring that has occurred during major maintenance activities in the past five years, and a description of measures that can be used to perform these activities with a minimum of flaring. For purposes of this section, planned maintenance is interpreted as scheduled process unit turnarounds as well as more near-term shutdowns planned within the refinery's maintenance planning process.

5.1.1 When Flaring is Likely to Occur During Maintenance and Turnaround Activities

Maintenance activities may result in a higher than normal flow of material to the flare gas recovery system. In order to maintain process equipment, the first step is to clear the process equipment and associated piping of hydrocarbons, before the system is opened to the atmosphere, for both safety and environmental reasons, including compliance with BAAD Regulation 8 Rule 10, (Process Vessel Depressurization). For catalyst-containing vessels, hydrocarbon removal is also done to address solid waste disposal issues. How this is accomplished depends on the physical properties of the hydrocarbons to be removed (e.g., vapor pressure, viscosity, etc.) and on the process details of the equipment that is to be maintained.

Efforts are made to recover as much of the hydrocarbon as possible by transferring it for processing in another part of the refinery, i.e., one that is not undergoing maintenance. For example, liquid hydrocarbons can be pumped to tankage or another process unit; gases under pressure may be depressurized to another process unit. Heavy hydrocarbons that are viscous at ambient temperatures are often displaced from the equipment to be maintained using lighter hydrocarbons {e.g., light cycle oil (LCO)}. The LCO is then pumped from the equipment.

Although depressurization and pump-out can be used to remove the bulk of the hydrocarbon from the equipment, some residual material remains. Following pump-out or depressurization to other process equipment, the next step in preparing for maintenance typically requires a low-pressure location that has the ability to accept a wide range of hydrocarbon materials in order to avoid venting these materials to the atmosphere. The relief gas header is the only location within the refinery that meets these criteria. Equipment items containing materials that are gases at ambient temperatures and pressures are often vented to the flare gas recovery system so that the hydrocarbon can be recovered as fuel gas. To free equipment of hydrocarbons following depressurization, they can be purged using steam, an inert gas such as nitrogen, or recently certain recycle process gas streams have been used as a way of minimizing load on the relief system. The decision to use steam, nitrogen, or recycle gas depends on the nature of the material being purged; heavier hydrocarbon fractions are more effectively removed using the thermal properties of steam, while lighter fractions can be removed more effectively with nitrogen. The decision also depends on physical considerations such as avoiding causing corrosion by steam condensing or damaging catalysts. These assessments to determine the purge medium reduces flaring by ensuring that hydrocarbons are removed in the most effective manner, reducing the overall load burden on the FGR system.

For equipment containing liquids, steam or nitrogen are often used to “blow” the liquid to the relief gas header. The liquid hydrocarbon and condensed steam are separated from the vapor phase in knockout drums, and returned to the refinery’s recovered oil or sour water systems. Nitrogen with hydrocarbon vapor continues on to flare gas recovery. Once the bulk of the liquid hydrocarbon has been displaced, the flow of steam or nitrogen is continued to remove any residual hydrocarbon by vaporization. Steam can be more effective for heavier materials as it increases their volatility by increasing temperature.

Chemical cleaning by circulating solvents and proprietary aqueous solutions is used to de-oil or oxidize pyrophoric materials when present within equipment. These circulation operations are generally open to the relief system but do not have significant impacts on flare operations. Chemical cleaning can reduce the quantity of gas that needs to be flared (although the hydrocarbon-containing liquids must still be treated as an oily waste water). More often, chemicals are injected as part of the process of steaming-out equipment to the relief system. This facilitates the steam-out process and reduces the total time required for steaming-out equipment. The decision to use chemical cleaning is made as part of the IMPACT planning process. The chemical cleaning coordinator meets with each IMPACT team prior to the turnaround to develop this work scope.

Although these procedures eliminate hydrocarbon emissions related to equipment opening, they require a high volumetric, high velocity, steam or nitrogen flow rate in order to be effective. This high flow rate of inert gas can create several sets of circumstances where flare gas cannot be recovered due to the change in fuel gas composition (increased molecular weight or temperature) or to the increase in volumetric flow rate.

In addition to an increase in flare gas average molecular weight from a higher than normal nitrogen flow rate, there is also the potential for much lower than average molecular weight gas from increased flow of hydrogen. There are many process and reactor systems within a refinery that contain gases with high hydrogen content. When this equipment is depressurized to the relief gas header, there can be a sharp decrease in the flare gas average molecular

weight. The effect of such changes in the quality of recovered relief gases can create situations where the FGR compressors cannot recover the gas without over-heating and possibly being damaged.

5.1.2 The Effect of Flare Gas on Downstream Equipment

Gas composition affects the equipment in the flare gas recovery system. Specifically:

- High nitrogen content can impact heaters, boilers and flare gas compressors.
- Hydrogen and other low molecular weight gases impact flare gas compressor performance.
- Steam impacts knock out drums and compressors, while increasing sour water production.

High flows of nitrogen from equipment purging lead to a much higher than normal inert content in the mixed flare gas and greatly reduce 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 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 heater or boiler, leading to a potential explosive risk 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.

The higher than normal nitrogen content of flare gas that can result from nitrogen purging has the effect of greatly increasing its molecular weight. Reciprocating compressors increase the pressure of a constant inlet volumetric flow rate of gas. For a given volume of gas, an increase in molecular weight creates an increase in its mass. This increases the work that the compressor has to do to compress the gas, overloading and potentially damaging the equipment.

For most flare gas systems that make use of reciprocating compressors, the compression ratio (outlet pressure/inlet pressure) is high enough that more than one stage of compression is needed. The temperature of the gas increases as it is compressed. 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 (e.g., high hydrogen content, etc.) can lead to a temperature increase exceeding the design limitations of the equipment. Continuing to operate at such temperatures can lead to serious damage and failure of the compressor.

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 relief 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 (i.e., to a flare) in order to avoid mechanical damage. Another disadvantage of the use of steam is that most of what is added as a vapor will condense in the relief gas headers and 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. This creates a sour water stream requiring treatment.

Each of the situations described above potentially leads to the need to divert gas produced during refinery maintenance away from the flare gas compressor and to a flare. This is a

necessary result of maintenance procedures which have been adopted to minimize the release of hydrocarbons to the atmosphere during equipment opening. The need to divert gas is driven by the quantity and composition of the gases produced during equipment shutdown and startup.

5.1.3 Past Flaring due to Major Maintenance Activities

A review of maintenance-related flaring at the Richmond Refinery during the five years prior to the promulgation of Regulation 12, Rule 12 (on July 20, 2005 was completed and has been included in Table 5-1 of the original FMP). The implemented planned improvements to reduce flaring originally included the FMP's Table 4-1 have been updated and moved to Table 5-1 during the first FMP annual update.

The process used to develop information included in Table 5-1 was to review past flare plans for planned major maintenance work (prepared as part of the Richmond Refinery's existing shutdown planning process) as well as the available refinery annual release reporting summaries (containing actual flaring emissions calculated for major flaring events). These plans and reports were reviewed to identify dates, and to identify and understand general steps followed during shutdown and startup that might be expected to result in flaring. Lessons learned, resulting in the adoption of best practices and potential ideas for flaring reductions, were discussed with subject matter experts and are listed in the table for each general category of planned major maintenance work.

Based on the types of lessons learned from the 5-year review, the greatest potential for further cost-effective reductions in flaring is to update and improve existing operations and maintenance procedures. These flaring reduction measures satisfy safety and maintenance obligations, and also address the conditions (described in the preceding sections) that prevent recovery of relief gases. In practical terms this means taking a series of actions specific to the unit undergoing maintenance to limit the rate at which relief gases are generated and maintain gas temperature and composition within an acceptable range for handling by the flare gas compressor and eventual use in a fuel gas system. Concepts for accomplishing this are discussed below in this section.

Per the IMPACT planning process for maintenance turnarounds a flare plan is prepared as part of the turnaround planning process. This plan identifies a schedule of discrete work steps such as pulling feed, shutting down, depressuring, and cleaning up units and equipment that could generate flare gas to relief. Consideration is given to whether relief gases can be recovered or routed to another location besides relief. The IMPACT process for planning major maintenance turnarounds includes a "lessons learned" session to incorporate learnings into the next subsequent turnaround. The Refinery has developed a process to formalize the "lessons learned" in order to capture and document learnings. Refer to the fuller description of the IMPACT planning process in Section 5.1.6 for how these activities and lessons learned would be applied to future turnarounds. Gases are routed to FGR compressors as long as the heat generated by compressing these gases does not exceed the discharge temperature of the compressor, which could damage it and, therefore, result in flaring due to the loss of FGR compressor operation. Section 5.2.4 addresses options for flare gas recovery, treatment and re-use.

Table 5-1 Past Flaring During Major Maintenance Activities and Improvements Implemented

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
January 2002 April 2002 September 2002 January 2003 March 2003 December 2003 January 2004 September 2004 November 2004 May 2005	4 & 5 Rheniformer regenerations	During the January 2003 regeneration, a test run was conducted. The Rheniformer's reactor section was depressured directly to the refinery's fuel gas system. Prior to this date, Rheniformer regenerations were conducted with the vent gases generated during the reactor depressuring step routed to the flare or FGR.
April 2002 February 2005	TKC plant shutdowns	TKC plant reactors were depressured (from 2600 to 275 psig) by routing gases to the #20 Plant (Hydrogen Recovery) rather than to the FGR system. Depressuring to hydrogen recovery or locations other than the relief system reduces the load on the FGR system, and reduces the likelihood of flaring. Evaluation of this is part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
November 2001 October 2003 January 2004 October 2004	TKC plant catalyst module change-outs	TKC plant catalyst modules (R-410/411 and R-420/421) were depressured (from 2600 to 275 psig) by routing gases to the #20 Plant (Hydrogen Recovery) instead of to the flare gas recovery system. Depressuring to hydrogen recovery or other locations besides the relief system reduces the load on the FGR system, and reduces the likelihood of flaring. Evaluation of this is part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
February 2001 January 2003	TKN-ISO plant shutdowns (applies to module shutdowns as well)	TKN/Isomax plant reactor modules (R-610/620) were depressured from 1300 to 275 psig routing to #20 Plant (Hydrogen Recovery). TKN plant reactor (R-510) was also depressured to 20 Plant (H2 Recovery) instead of to the FGR system.
February 2001 January 2002 January 2003 January 2004 February 2005	H2 Manufacturing Trains	20 Plant/V-340 (natural gas) depressured to FGR (stay on FGR). 20 Plant is nominally part of the hydrogen train system- hydrogen trains themselves are not depressured to the flare when undergoing a turnaround. Depressuring 20 Plant to FGR is evaluated as part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
January 2002	RLOP complex: HNC/LNC/HNF/LNF	Depressure reactors to #20 plant (H2 Recovery) and then to FGR if possible. Depressuring to hydrogen recovery or other locations besides

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
		the relief system reduces the load on the FGR system, and reduces the likelihood of flaring. Evaluation of this is part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
January 2002	D&R complex: 4CU/4&5 Rhen/NHT/JHT/DHT/ Penhex Isom/Naphtha splitter/Reformate splitter	Route gases from rapid purge & depressurization with nitrogen ("pop and purge") to FGR instead of to flare as long as the heat that is generated by compressing the gases does not cause the operating temperature of the FGR system to activate the temperature alarm on the compressors.
November 2003	FCC / Alky planned	Route vent gas to FGR instead of to flare as long as the heat that is generated by compressing the gases does not cause the operating temperature of the FGR system to activate the temperature alarm on the compressors.
February 2005	SDA major shutdown	Route vent gas to FGR instead of to flare as long as the heat that is generated by compressing the gases does not cause the operating temperature of the FGR system to activate the temperature alarm on the compressors.
Multiple dates	FGR maintenance	Schedule necessary preventive maintenance on the FGR compressors at times when the demands on FGR system are low. Avoid scheduling maintenance during turnarounds as long as the key parameters monitored, including valve temperatures, oil temperatures, and stage pressures, indicate that the compressors can run reliably through the clean-up process. This reduces the likelihood that demands on the FGR system would exceed the capacity of the available FGR compressor, thus reducing the likelihood of flaring. Maintaining the FGR compressors prevents failures and keeps them operating. When the FGR compressors operate reliably, flare gases are recovered instead of flared.
October 2005	FCC major shutdown	Separated FCC and Alky flares after pulling feed from FCC unit in order to facilitate separate clean-ups of each unit. Specific improvement opportunities based on the FCC 2005 shutdown will be incorporated into the IMPACT planning process for future maintenance turnarounds when that turnaround scope is defined.
November 1, 2007	For each maintenance turnaround where nitrogen will be blown	Incorporate for consideration as part of the updated flare planning procedure (see section 5.1.6). A checklist has been added to the flare

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
	through vertical furnace tubes, an evaluation will be made by the IMPACT team on whether reducing the duration of purging or decreasing the nitrogen flow rate would still allow the tubes to be cleaned, which could reduce flaring where nitrogen cannot otherwise be recovered without exceeding the temperature limit of FGR compressors.	planning procedure that requires an evaluation of the ability to reduce flaring by optimizing furnace tube blowing times when furnaces with vertical tubes are being cleared of hydrocarbon in this manner.
November 1, 2007	Reduce duration and/or decrease flow rate at which Nitrogen is used to purge plant equipment, as long as plant equipment can be cleaned-up for maintenance.	For each maintenance turnaround, an evaluation has been made by the IMPACT team on whether reducing the duration of purging or decreasing the nitrogen flow rate would still allow plant equipment to clean-up sufficiently for maintenance. This could reduce flaring where nitrogen cannot otherwise be recovered without exceeding the temperature limit of FGR compressors. See Section 5.1.6 for the IMPACT process. A checklist has been created and used to document the results of this evaluation.
November 1, 2007	#4 and #5 Rheniformers depressure directly to fuel gas system except if prevented by the piping configurations and/or manifold of valves	The catalytic reformers (#4 and #5 Rheniformers) have been directly depressured to the fuel gas system (rather than going through the relief gas header and flare gas recovery system) since 2003. A checklist has been added to the flare planning procedure that requires an evaluation of the ability to reduce flaring by continuing to depressor the catalytic reformers directly to fuel gas system.
Implemented Prior to August 1, 2006	Update controls for RLOP plant's E-1900 to reduce risk of hydrate plugging problems. - low outlet temperature alarms on E1900 and E1901 heat exchangers, - valve position alarm on the temperature bypass valve at E1900, - reduce the set point for the low flow alarm on the	An extensive sampling effort was conducted to evaluate potential sources of chlorides into the relief system. It was determined that the source of chlorides into the relief system was caused by blowing down perchloroethylene lines to relief during steps in the catalyst regeneration process for the Rheniformers. Rheniformers upgrade lower octane feed to higher octane by passing a mixture of these hydrocarbons and hydrogen over a catalyst. The catalyst must be regenerated periodically. Perchloroethylene is used as a chloriding agent

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
	1 st stage of K1900 compressor - valve position alarm on the pressure control valve to relief.	to rejuvenate the catalyst during the regeneration process. To reduce this source of chlorides, the 5 Rheniformer Regen Procedure was revised to lessen the amount of perchloroethylene that is purged to relief during the regeneration process. The main intent of these changes is to maintain lower levels of perchloroethylene in the perchloroethylene
Study Concluded prior to August 1, 2006 and actions taken in August 2007	Study and evaluate solutions to address South Yard Relief System's Ammonium Chloride issues (Abrasive ammonium chloride salts had built up in the K-3950 compressors, causing it to shutdown.). Issues resolved in August 2007.	An extensive sampling effort was conducted to evaluate potential sources of chlorides into the relief system. It was determined that the source of chlorides into the relief system was caused by blowing down perchloroethylene lines to relief during steps in the catalyst regeneration process for the Rheniformers. Rheniformers upgrade lower octane feed to higher octane by passing a mixture of these hydrocarbons and hydrogen over a catalyst. The catalyst must be regenerated periodically. Perchloroethylene is used as a chloriding agent to rejuvenate the catalyst during the regeneration process. To reduce this source of chlorides, the 5 Rheniformer Regen Procedure was revised to lessen the amount of perchloroethylene that is purged to relief during the regeneration process. The main intent of these changes is to maintain lower levels of perchloroethylene in the perchloroethylene injection pot, prior to moving to a step that requires the injection system to be purged. In addition, during certain steps the perchloroethylene will be emptied into the reactors to avoid purging it to the relief system. Two Carbon drums in series have been installed on the bulk storage perchloroethylene drum (V-3592) off gas line to minimize formation of salts in the south yard relief system. Operating procedures have been revised and operator crews have been trained to follow these procedures.
November 1, 2007	Update of startup procedures to prevent equipment (such as plant recycle compressors) malfunction	An evaluation is made for each maintenance turnaround by the IMPACT team on whether clearing equipment of liquid by blowing nitrogen through it would be useful or required to prevent damage on start-up, and therefore reduce flaring by preventing unplanned malfunctions. A checklist has been created and used to document the results of this evaluation.

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
December 31, 2006 -complete	Upgrade relief line flow meters in the North Yard, and install additional new relief line flow meters in the South Yard.	Flow meters on the North Yard and South Yard relief system branch lines were upgraded to GE Sensing Model Number 868 meters. A total of 42 meters were installed, 17 in the South Yard and 25 in the North Yard. These meters are more accurate than the meters which were previously installed, making it easier to determine where sources are flowing into the relief system. Locating these sources enabled them to be controlled, thus reducing the load on the NY and SY FGR systems and therefore reducing the likelihood of flaring.
Implemented Prior to August 1, 2006 - complete	Upgrade and configure the RLOP Plant's K-1960 compressor to provide additional (spare) flare gas recovery capacity	K-1960 draws on and compresses vented vapors from many RLOP plants as well as relief gas from the North Yard flare system. K-1960 can be loaded and unloaded either automatically or manually on a local panel. K-1960 has a maximum capacity of 1.29 MM SCFD and normally runs at 100% of load (unless starting or shutting down unit). Commissioning K-1960 effectively reduced the load on the North Yard FGR system by 1.29 MMSCFD, thus reducing the likelihood of flaring occurring. Overall loading on the North Yard FGR system in SCFD can be monitored from desktop interfaces and compared to their combined capacity of 7.92 MMSCFD. K-1960 is a Cooper Energy Services two-stage reciprocating compressor.
Study Concluded prior to August 1, 2006	Study potential K-3950 Flare Gas Recovery compressor upgrades to handle gases with higher heat of compression	K-3950 is a Cooper Energy Services two-stage reciprocating compressor. A study concluded in June 2006 identified upgrades to enable K-3950 to handle gases with higher heats of compression, increasing the proportion of nitrogen that can be recovered. These included valves with a wider port and larger valve area, and upgrading the sealing plates from steel to an engineered plastic. Upgraded suction valve actuators would eliminate the need for time-consuming adjustments every time they were removed. Completion of the internal modifications had been delayed because in order to manufacture the upgraded parts, several dimensions on each valve port had to be checked with K-3950 down and the valves removed. Completed in January 2007, these upgrades enable K-3950 to stay on-line longer during the shutdown clean-up process without damaging the machine, thereby reducing flaring

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
December 31, 2006	All refinery flares to be compliant with the requirements of federal New Source Performance Standards (NSPS), Subpart J	Six Refinery flares have been certified to be used only for start-up, shutdown or malfunction (SSM), and therefore would not be used for routine flaring. In order to meet this SSM requirement, source control efforts were implemented including monitoring of spare flare gas recovery capacity, identifying sources of increased flows to the flare gas recovery system, and actively pursuing elimination of increased flows. The seventh refinery flare was certified in October 2007 as complying with NSPS subpart J, and therefore only used for SSM.
November 1, 2007	Improvements on procedure for shutdown planning (and planned maintenance flare planning)	A maintenance work planning and scheduling procedure has been developed for evaluating the impact of flaring from planned maintenance work outside of plant shutdowns. The procedure incorporates a review for the impact on the relief/flare gas recovery system from performing planned maintenance work and the potential to minimize the flaring. In addition, for shutdown flare planning, a step has been added to the procedure to evaluate the flare plan for minimization opportunities including evaluation of items in the checklist referenced in other rows of this table. Lessons learned have been incorporated in the flare planning procedure.
Implemented Prior to August 1, 2006	Increase temperature alarm set points and procedures to take advantage of K-1060 and K-1070 Flare Gas Recovery compressor material upgrades.	K-1060 and K-1070 North Yard flare gas recovery compressors (Worthington, two stage, three cylinder, reciprocating) had modifications to internal parts and auxiliary systems to increase reliability and potential ability to handle gases with higher heats of compression (e.g., Nitrogen, Hydrogen). Internal modifications included material upgrades to piston parts. The internal modifications were completed in several stages, incorporating lessons learned to allow for a slight increase in operating temperature, which would enable plants to stay on FGR for a longer period of time during some clean-up operations. Modifications to auxiliary systems including adding a spare pump to the FGR compressor knockout drum to reduce the chance of the system shutdown, and adding supplemental cooling to a relief drum to enhance gas recovery. The higher discharge temperature for K-1060 and K-1070 and measures to increase reliability will directionally allow plants to remain on FGR for longer periods during shutdown purge and cleanup operations, and start-up activities.

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
November 1, 2007	Initial reactor depressure from high to low pressures (275 psig) are routed to the Hydrogen Recovery Plant 20, or other suitable process location. The secondary depressure vent gas is sent to the flare or flare gas recovery dependant on if compressor capacity is available.	For each maintenance turnaround an evaluation has been made by the IMPACT team on whether North Yard reactors can be depressured to Hydrogen Recovery Plant 20, or other plants, instead of to relief, and therefore reduce the quantities of gas that must be flared. Depressuring the hydrogen to other process locations reduces flaring by allowing the hydrogen to be consumed within the process system, and by routing it to a process system rather than sending it to flare gas recovery, it frees up capacity on the FGR compressor to manage the overall flare load more effectively. See Section 5.1.6 for the IMPACT process. A checklist has been created and used to document the results of this evaluation.
November 1, 2007	Route purge gases from DHT, JHT, and NHT plant shutdowns to #5H2S plant or alternate process locations, except if #5H2S is down, or gases contain too much nitrogen or steam to introduce to the fuel gas system.	For each maintenance turnaround an evaluation will be made by the IMPACT team on whether DHT, JHT and NHT plant turnarounds can be purged to #5H2S or other process locations, instead of to relief, and therefore reduce the quantities of gas that must be flared. See Section 5.1.6 for the IMPACT process. A checklist has been created and used to document the results of this evaluation.
December 31, 2007	Conversion of K-242-and K-252	K-242 and K-252 compressors have been converted to provide additional flare gas recovery capacity in the South Yard. These conversions provide additional, dedicated flare gas recovery compressor capacity and reduce the dependency on the dual role K-1171 and K-1171A compressors. K-242 and K-252 compressors are Worthington two-stage, reciprocating units with a capacity of between 1.9 and 2.3 MMSCFD per compressor, depending on the molecular weight of the gas. Either K-242 or K-252 compressor is available for back-up FGR service (with the other compressor in dual process/FGR service). K-242/K-252 provide approximately 2 MMSCFD dedicated back-up capacity to the existing flare gas recovery capacity of 2.35 MMSCFD provided by K-3950. With an additional 1.7 MMSCFD available from the dual service K-1171 and K-1171A, a total of 6.1 MMSCFD flare gas recovery capacity is provided against the current base load of 0.8 MMSCFD.

<i>Date (s)</i>	<i>Description of Activity Resulting in Flaring</i>	<i>Lessons Learned from Past Actions</i>
		The conversion of K-242 and K-252 was completed in December 2007.
June 2011	North Yard FGR compressor electrical power upgrade	Upgrade the North Yard FGR compressor's common electrical power supply system to separate feeders so that when one FGR compressor is shut down for maintenance, the other FGR compressor will be in service.
October 4 – 11, 2011	RLOP complex: HNC/LNC/HNF/LNF	A steam condenser was designed and installed to reduce loading on the relief system during steam cleaning of the process equipment. Evaluation of this is part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
October 8 – 12, 2011	D&R complex: 4CU/4&5 Rhen/NHT/JHT/5H2S/ Penhex Isom	A steam condenser was designed and installed to reduce loading on the relief system during steam cleaning of the process equipment. Evaluation of this is part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
October 2015	FCC major shutdown	Separated FCC and Alky flares after pulling feed from FCC unit in order to facilitate separate clean-ups of each unit. A steam condenser was designed and installed to reduce loading on the relief system during steam cleaning of the process equipment. Evaluation of this is part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
October 2016	RLOP and D&R Major Shutdown	A steam condenser was designed and installed to reduce loading on the relief system during steam cleaning of the process equipment. Routed an off gas stream to a gas recovery unit to allow greater flare gas recovery capacity. Evaluation of this is part of the IMPACT process. See Section 5.1.6 for the IMPACT process description.
December 2016	RLOP Startup	Utilized an off gas and flare gas recovery load to start up a critical compressor. Additional loading upon startup improved performance and minimized flaring.

5.1.4 Past Flaring Activities Requiring Causal Analyses

A list of reportable flaring events that required causal analyses at the Richmond Refinery from January 2020, to the end of the current reporting FMP period (July 1, 2024 – June 30, 2025) has been included in Table 5-1a of the FMP annual updates. The description of the cause (or

causes) and any contributing factors resulting in these flaring activities are included in this FMP annual update.

Lessons learned, resulting in the adoption of best practices and potential ideas for flaring reductions, were discussed with subject matter experts and are listed in the table for each flaring activity that resulted in causal analyses to be conducted.

Table 5-1a Flaring Activities Requiring Causal Analyses (January 1, 2020 – June 30, 2025)

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
February 10, 2020	A pressure swing adsorption system at the Hydrogen Plant had been out of service for maintenance and isolated from a hydrogen feed compressor with a valve. During maintenance of the pressure swing adsorption system, the hydrogen feed compressor tripped due to insufficient isolation by the valve. The hydrogen feed compressor shutdown reduced hydrogen feed to downstream units. This led to an unstable process condition at the Taylor Katalytic Denitrifier (TKN) Unit of the Hydroprocessing Area Business Unit. Due to the unstable condition, process gases were depressured to relief per procedure.	The following corrective actions were assigned following the incident: (1) Update the pressure swing adsorption system isolation procedure to take into account that the valve does not isolate the pressure swing adsorption system from the hydrogen feed compressor.
February 16, 2020	A reactor experienced a temperature excursion in the Taylor Katalytic Denitrifier (TKN) Unit of the Hydroprocessing Area Business Unit. The hydrogen recycle gas controller for the reactor was operating in manual control. Operations attempted to control the temperature excursion by making process moves, but there was insufficient hydrogen recycle gas flow during the response. After troubleshooting, the reactor was depressurized to relief to control the temperature excursion, and flaring began. The Automatic Depressurization System (ADS) timer for the reactor activated due to low hydrogen recycle gas flow, and flow was routed to relief.	The following corrective actions were assigned following the incident: (1) Provide refresher training to Operations crews on the reactor ADS timer function and the activation on low hydrogen recycle gas flow. (2) Provide refresher training to Maintenance schedulers on diligent management of higher priority work requests.
February 22, 2020	While troubleshooting a plant upset, acid gas was routed to an emergency scrubber in the #5 Hydrogen Sulfide (#5 H ₂ S) unit of the Distillation and Refining Business Unit. The ammonia flow ratio into the emergency scrubber bottoms recirculation system was insufficient for absorption, and the emergency scrubber overhead vapor flow went to the relief system.	The following corrective actions were assigned following the incident: (1) Add a dP instrument to the exchanger and dP indication to the control board main page. (2) Repair the emergency scrubber overhead vapor flow meter. (3) Add an alarm for the emergency

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
		scrubber overhead vapor flow. (4) Convert job aid to startup emergency scrubber into a procedure.
August 14, 2020	After ambient temperatures reached approximately 90 deg F, the fire suppression system at the Cogeneration Train 1000 Unit (Utilities and Environmental Area Business Unit) activated. This was due to a false interpretation of a pull from a pull switch station handle, causing the steam producing unit to trip. The sudden loss of steam header pressure caused an unstable process condition, and process gases were depressured per process controls.	The following corrective actions were assigned following the incident: (1) Install shade over pull switch station to prevent from overheating. (2) Evaluation of alternatives for long-term solutions for pull switch system failure and implementation plan development.
November 2, 2020	During testing of the tone-based communication system between the SOSS (Standard Oil Switching System) and two electrical substations (#2 and #4), a trip of the substation breakers caused a loss of power to the Hydroprocessing ABU (Area Business Unit). This was due to an incorrectly labeled drawing that did not match the circuitry in the field. Loss of power to units in the Hydroprocessing Area Business Unit led to process gases being sent to the relief system.	The following corrective actions were assigned following the incident: (1) Submit updated elementary drawings to drafting. (2) Add labeling to relays located in 2 and 4 Substation high side buildings. (3) Update protective relay & metering diagrams for 2 and 4 Substation. (4) Meet with procedure owner to discuss whether Protection Relay Diagrams should be Process Safety Instrumentation (PSI) documents. (5) Develop a procedure for testing the tone-based communication system and include when a written work plan is required. (6) Determine whether implementing field verification of the Foreign Prints and Protective Relay Diagrams for the SOSS (Standard Oil Switching System) would reduce the likelihood of a recurrence.
November 3-8, 2020	The Chevron Richmond Refinery began start-up of Hydrogen Plant Trains 1 and 2 following the power outage on November 2. The Hydrogen plant start-up procedures include routing flows to relief. The Hydrogen Plant does not have any flare gas recovery or a water seal, and therefore all relief flows result in flaring.	Flaring cannot be prevented during plant start-up due to facility and relief system design. Operational activities were consistent with start-up procedures.

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
November 8-10, 2020	Multiple process units in the Hydroprocessing ABU (Area Business Unit) were starting up following unplanned shutdowns. Due to the start-up operating conditions, the Flare Gas Recovery (FGR) system had a high base load. In addition, a FGR compressor startup was delayed and part of the FGR system began to build up differential pressure. Both issues reduced the FGR system's capacity to capture process gases.	The following corrective actions were assigned following the incident: (1) Assess whether compressor should be resized (as part of next process unit financial study). (2) Review FGR Compressor startup procedure. Consider adding a new scenario related to starting up after an unplanned outage.
November 25, 2020	A compressor in the Hydroprocessing ABU (Area Business Unit) tripped offline during performance of planned online maintenance testing. Attempts were made to restart the compressor but were unsuccessful. Feed was subsequently pulled from the process unit, leading to flows to the Flare Gas Recovery (FGR) system exceeding FGR capacity, and process gases were sent to the flare relief system.	The following corrective actions were assigned following the incident: (1) Design review against API standards and scope for TA as appropriate. Consider adding a bleeder valve as mitigation or moving block valve to be upstream of dump valve. (2) Design review of dump solenoid orifice sizing to ensure proper operation for both speed and function.
December 1, 2020 – March 8, 2021	A flaring event as defined by Regulation 12, Rule 12, Section 208 occurred at the H2 Plant Flare. Operations determined that the increase in vent gas flow was due to a faulty pressure control valve with positive isolation at the Hydroprocessing ABU (Area Business Unit). Gases from the pressure control valve were routed to the H2 Flare (not vented directly to atmosphere). Initial repairs made to the faulty pressure control valve were temporarily successful in stopping the flow; however, these repairs did not hold for an extended period of time. Efforts to minimize the vent gas flow were implemented, and the valve was successfully repaired on March 8, 2021.	The following corrective actions were assigned following the incident: (1) Repair the Valve at the H2 Train Within an Operating Window that Reduce Impacts to the Other Plants and thus Minimizes Flaring.
December 10, 2020	A unit in the Hydroprocessing Area Business Unit (ABU) initiated a shutdown. During this process, Operations attempted to shutdown a pump per procedure, but a faulty breaker prevented the pump from shutting down. The unit was subsequently de-	The following corrective actions were assigned following the incident: (1) Replace faulty breaker in pump. (2)

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
	pressured, sending flows to the Flare Gas Recovery (FGR) system exceeding FGR capacity, and process gases were sent to the flare relief system.	Inspect internal components of pump to ensure proper future operation.
January 21, 2021	Acid gas was routed to an emergency scrubber in the Distillation and Refining Area Business Unit (D&R ABU) consistent with the Flare Minimization Plan (FMP) during startup of a unit. While high flows were being routed to D&R ABU for purposes of unit startup, low suction pressure caused a flare gas recovery compressor to trip offline. The low suction pressure resulted in a flow ratio that was insufficient for absorption in the emergency scrubber bottoms recirculation system. Emergency overhead vapor flow that resulted went to the flare relief system.	The following corrective actions were assigned following the incident: (1) Determine cause of low/no flow indication on emergency scrubber feed meter. Implement solution to read lower feed rates. (2) Add step in start-up procedure to ensure aqueous ammonia flows to the emergency scrubber whenever the emergency scrubber's feed valve is open. (3) Lower high-level alarms on liquid recovery drum to prevent pressure build-up. (4) Modify start-up procedure to include re-routing flows from H2S units, preventing an overload of flow to that unit.
March 12, 2021	The Chevron Richmond Refinery started up Hydrogen Plant Train 2. The plant had been shut down to repair a faulty pressure control valve. The Hydrogen plant start-up procedures include routing flows to relief, which resulted in flaring.	Flaring cannot be prevented during plant start-up due to facility and relief system design. Operational activities were consistent with start-up procedures.
May 2, 2021	An intermittent water wash was conducted at a heat exchanger as part of a routine preventative maintenance activity. During this time, a temperature spike in the heat exchanger occurred, leading to excessive liquid into a compressor knockout drum and a shutdown of the compressor. Flows sent to the Flare Gas Recovery (FGR) system exceeded FGR capacity, and gas was routed to the flare relief system.	The following corrective actions were assigned following the incident: (1) Improve process monitoring at the heat exchanger by updating procedure and providing recommendations for frequency of water wash. (2) Improve process indications at the heat exchanger by evaluating instruments and providing recommendations to improve heat exchanger instrument reliability and accuracy. (3) Improve wash water procedure by addressing plant posture required and amount of wash water needed to conduct a water wash. (4) Review

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
		incident with crews to implement mitigations to aid in the prevention of a recurrence.
May 14, 2021	On the morning of May 14, 2021, operators at a process unit received audible alarms, and upon investigation, discovered a fire at a pump within the process unit. Operators made immediate notifications to plant personnel and activated in-plant fire suppression systems. The Refinery's Fire Department was notified and responded to extinguish the fire. Operators pulled feed from the impacted unit and placed it in a controlled stable posture. The area safety flares activated at approximately 05:32 during the plant shutdown.	The following corrective actions were assigned following the incident: 1. Upgrading of the seal system design. 2. Improving operator rounds pertaining to monitoring of the seal system of the pump. 3. Assuring appropriate groups are communicating (nuisance alarms, operational concerns, pump monitoring) in the proper forums. 4. Reinforcing the use of shift turnovers to document when the vibration trip systems are disarmed. 5. Management actions to reinforce appropriate management of the vibration trip system. 6. Additional training regarding the suction air operated valves. 7. Redesign the piping system using current design tools. This measure is complete as of July of 2021.
May 27, 2021	The Refinery experienced the loss of all boilers in operation which caused a significant loss of refinery steam production. The boilers tripped offline because of an activation of a safety system due to a significant change in fuel gas composition being delivered to the boilers. The fuel gas composition change occurred when a different process plant was brought online that supplies fuel gas to the refinery. The loss of refinery steam production caused the slowing of a steam driven compressor in another unit, causing that unit to vent process gases to the Flare Gas Recovery (FGR) system as designed.	The following corrective actions were assigned following the incident: (1) Update process plant startup procedure to include notifications to Power Plant Operations prior to initial pressurizing and startup. (2) Consider implementing automatic logic and controls to better manage fuel gas composition variations at the Power Plant boilers.
July 25-26, 2021	On July 25th, 2021, the Refinery experienced two momentary disruptions on the 115kV electrical transmission system. The	The following corrective actions were assigned following the incident:

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
	momentary disruptions led to voltage sags at the substations. As a result of the voltage sags, hydrogen production plants shut down in response to pressure issues on Train 1 and loss of air flow on Train 2. Hydrogen plant shutdown procedures include routing flows to relief and subsequent flaring.	<ol style="list-style-type: none"> 1. Review preventative cleaning program for 115 kV electrical system. Evaluate increasing the frequency of insulator cleaning on 115 kV system. 2. Redesign and implement new control relay coordination and logic of the 4kV motor control at the H2 Trains.
August 8, 2021	On August 8th, 2021, Hydrogen Plant Train 1 started up following a trip of Train 1. The trip was due to a feed gas compressor unloading during an alarm reset, leading to a loss of flow to Hydrogen Plant Train 1. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	<p>The following corrective actions were assigned following the incident:</p> <ol style="list-style-type: none"> 1. Update control logic to ensure feed gas compressors do not unload during alarm reset.
August 10, 2021	<p>On August 10, 2021, visible flaring occurred at the FCC and Alky flares due to a faulty pressure transmitter on a drum which resulted in an unexpected slowdown of an FCC compressor. Additionally, the steam valve on the FCC Flare malfunctioned which limited the operator's ability to increase steam to reduce smoking at the FCC flare, resulting in visible emissions.</p> <p>Operations immediately responded by troubleshooting and temporarily placed the spillback valves for the FCC compressor in manual control, and flaring stopped.</p>	<p>The following corrective actions were assigned following the incident:</p> <ol style="list-style-type: none"> 1. A pressure transmitter has been removed from the control logic system to aid in the prevention of an unexpected slowdown of an FCC compressor. 2. Identify any additional prevention measures with input from subject matter experts, including control logic vendor.
August 13, 2021	On August 13, 2021, Hydrogen Plant Train 2 started up following a unit shutdown. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant start-up due to facility and relief system design. Operational activities were consistent with start-up procedures.

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
August 14, 2021	On August 14th, 2021, the Refinery was starting up a hydrocracker in the Hydroprocessing Area Business Unit (ABU). As the plant was starting up, there was a faulty level reading in a high-pressure separator. This led to a pressure increase in a low-pressure separator (LPS), causing the LPS to relieve process gases to the Flare Gas Recovery (FGR) system. Flows sent to the Flare Gas Recovery system exceeded FGR system capacity, and gas was routed to the flare relief system. Operations pulled feed from the plant, reducing the pressure in the LPS. This stopped flows to the flare relief system, and the flaring ceased.	The following corrective actions were assigned following the incident: 1. Evaluate need for additional preventative maintenance on dP transmitters. If deemed necessary, determine the required frequency of preventative maintenance. 2. Add learnings from this event to hydrocracker startup procedure. 3. Conduct refresher training as necessary.
October 23, 2021	On October 23, 2021, Hydrogen Plant Train 1 had a planned shutdown to make repairs to the unit. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant shutdown due to facility and relief system design. Operational activities were consistent with shutdown procedures.
October 24-26, 2021	On October 24th, 2021, the Refinery experienced an outage of cogeneration units during a severe weather event. The initiating cause of the outage was a breaker fault caused by storm water intrusion during the severe rainstorm. A second cogeneration unit did not receive the designed back-up power supply and had to be shut down. With the loss of steam supply necessary to operate the Refinery, process units were shut down and flaring occurred. Storm water intrusion also caused a trip at a substation, which caused a power plant to lose power during troubleshooting. Operations responded by troubleshooting electrical equipment to restore power and steam to the Refinery for unit startup.	The following corrective actions were assigned following the incident: 1. Assess breaker design to reduce likelihood of water intrusion during severe rainfall. Implement appropriate recommendations from assessment. 2. Assess substation maintenance activities to reduce likelihood of water intrusion during severe rainfall. 3. Test cogeneration unit designed back-up power supply. Develop plan to improve power supply reliability. 4. Conduct relay coordination study. Develop plan to implement any appropriate learnings from the study.
October 27, 2021	On October 27, 2021, the refinery realized a significant drop in hydrogen gas demand due to an unplanned shutdown of refinery cogeneration units and the subsequent shutdown of hydrogen	Flaring cannot be prevented when the Hydrogen Plant realizes a sudden reduction in hydrogen demand from process units within the refinery. Prevention measures

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
	consuming process units, as discussed in Attachment 2. To safely manage the lack of hydrogen demand, hydrogen gas was sent to the flare relief system. Hydrogen production rates were lowered to minimize flaring, and the flaring event ended when hydrogen consumers came back online later that day.	identified for the shutdown of process units are discussed under separate reporting.
October 27, 2021	On October 27th, 2021, pressure checks were being performed at a unit in the Hydroprocessing Area Business Unit (ABU). While pressuring the system, a chopper valve and flow control valve failed to close on valve control logic due to faulty flow indicators. This allowed process gases to flow to the Flare Gas Recovery (FGR) System. Flows exceeded FGR capacity, and the gas was routed to the flare relief system. Operations manually closed and isolated the flow control valve. This stopped flows to the flare relief system, and flaring ceased.	The following corrective actions were assigned following the incident: 1. Consider alternate backflow prevention measures (physical or logic modifications based on other indicators).
October 30, 2021	On October 30th, 2021, a hydrocracker was starting up following the cogeneration outage discussed in Attachment 2. During this process, the system pressure rose as the unit was being prepared to introduce feed. The rising pressure lifted PRD's, sending process gases to the Flare Gas Recovery (FGR) System. Flows exceeded FGR capacity, and the gas was routed to the flare relief system. Operations investigated the source of relief and stopped flows to the unit via the pressure control system. Operations also lowered the system pressure to re-seat the PRD's. This stopped flows to the flare relief system, and the flaring ceased.	The following corrective actions were assigned following the incident: 1. Consider updating progressive alarms for unit system pressure to allow Operations sufficient time to take response actions.
November 1-5, 2021	On November 1st, 2021, a Flare Gas Recovery (FGR) compressor malfunctioned due to faulty valves in the compressor. Multiple attempts were made by Operations to troubleshoot the valves but were unsuccessful. To prevent further damage to the	The following corrective actions were assigned following the incident:

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	machine, the compressor was shut down, causing process gases to be routed to the flare relief system. Repairs were conducted and the compressor was put back in service on November 5, 2021. This stopped flows to the flare relief system, and the flaring ceased.	1. Repair the compressor in a timely fashion to put the machine back in service and minimize flaring. Repair was completed 11/5/2021.
November 6, 2021	On November 6, 2021, Hydrogen Plant Train 1 started up following repairs made to the unit. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
November 9, 2021	On November 9, 2021, a connector detached between the steam controller and positioner at a recycle compressor. This detached connector caused the compressor to slow to a stop. Operations attempted to restart the compressor but was unsuccessful. The unit was safely de-pressured as part of the process unit's shutdown procedure, causing process gases to be sent to the Flare Gas Recovery (FGR) system and exceeding FGR Capacity. Flows were routed to the flare relief system and flaring occurred. After the unit was de-pressured, Operations lowered the reactor pressure and temperature. This stopped flows to the flare relief system, and the flaring ceased.	The following corrective actions were assigned following the incident: 1. The connector between the steam controller and positioner was repaired. The repair was completed on 11/27/2021.
November 14, 2021	On November 14, 2021, the diesel hydrotreater (DHT) was starting up when a flange leak was discovered at an exchanger in the DHT. Operations responded by safely shutting down the DHT per procedure. Process gases flowed to the Flare Gas Recovery (FGR) System, and flows exceeded FGR capacity. The gas was routed to the flare relief system, and flaring occurred.	The following corrective actions were assigned following the incident: 1. Replace and tighten flange gasket to aid in the prevention of a reoccurrence. This work was completed on 11/14/2021.

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December 13, 2021	On December 13, 2021, a cogeneration unit that generates power and steam for the refinery shutdown due to the activation of a faulty fire alarm pull station. The subsequent loss of refinery steam production resulted in a shutdown of one of the refinery's process units. The unit was de-pressured in a controlled manner as part of the process unit's shutdown procedure, causing process gases to be sent to the Flare Gas Recovery (FGR) system and exceeding FGR Capacity. Flows were routed to the flare relief system and flaring occurred. Operations responded by restarting the cogeneration unit. Once steam production was re-established, flows to the flare relief system stopped, and the flaring ceased.	The following corrective actions were assigned following the incident: 1. Implement modifications to the existing pull stations based on Engineering recommendation.
December 30, 2021	On December 30, 2021, a reduction of liquid level in a gas recovery unit (GRU) column led to pressure increase in the column. This increase in pressure caused a pressure relief device (PRD) to lift, and process gases were sent to the Flare Gas Recovery (FGR) system, where the flows exceeded FGR capacity. The process gases were routed to the flare relief system and flaring occurred. Operations responded by stabilizing the GRU. This stopped flows to the flare relief system, and the flaring ceased.	The following corrective actions were assigned following the incident: 1. Repair faulty valve in a gas recovery unit. The repair was completed on 1/2/2022.
February 25, 2022	On February 25, 2022, refinery safety systems activated at a process unit in the Hydroprocessing Area Business Unit. This safety activation relieved pressure to the Flare Gas Recovery (FGR) System. Flows to the FGR System exceeded FGR capacity, and visible flaring occurred. Operations investigated and discovered a faulty relief valve in the process unit. In response, valves were closed upstream of the faulty relief valve. This step stopped the flow to the relief valve and ended the flaring event.	The following corrective actions were assigned following the incident: 1. Work with valve manufacturer and Chevron Corporate Engineering to identify potential fabrication improvements, including quality assurance and/or control actions.

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March 4, 2022	On March 4, 2022, liquid accumulated in a compressor knockout drum due to a process upset in an amine scrubber. As a result of increased liquid accumulation and potential for liquid carryover, a downstream compressor automatically shut down causing an increase in system pressure. Flows were then routed to the Flare Gas Recovery System to reduce the system pressure. Flows to the FGR System exceeded FGR capacity, and flaring occurred. Operations responded by stabilizing the liquid accumulation at the compressor knockout drum, which allowed the compressor to successfully start up. This stopped the flow to the relief system, and the flaring ceased.	The following corrective actions were assigned following the incident: 1. Evaluate amine scrubber internals for improved performance. 2. Perform training with crews regarding amine scrubber inflow temperatures.
March 16-17, 2022	On March 16, 2022, Hydrogen Plant Train 1 shut down as planned to perform maintenance. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant shutdown due to facility and relief system design. Operational activities were consistent with shutdown procedures.
April 16, 2022	On April 16, 2022, Hydrogen Plant Train 1 started up following a planned shutdown on March 16, 2022 to perform maintenance. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
May 22, 2022	On May 22, 2022, Hydrogen Plant Train 1 depressurized to relief due to low steam to carbon ratio. It was determined that the low steam to carbon ratio was due to valve faults within the plant. Operations shutdown Train 1 to perform valve repairs. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions.	The following corrective actions were assigned following the incident: 1. Evaluate addition of alarm for positioner controller feedback. 2. Consider installing bypass for control valves associated with this event. 3. Evaluate improvements to control valve work order process to ensure scope of work is fully executed.

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		4. Perform work order trainings with relevant personnel.
May 24-25, 2022	On May 24, 2022, Hydrogen Plant Train 1 started up following the plant shutdown referenced in Attachment 1. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
July 1-3, 2022	On July 1, 2022, the refinery's hydrogen production plant had a momentary loss of hydrogen production. As a result, two process units that consume hydrogen shut down. Hydrogen production was quickly re-established, but the hydrogen-consuming units were still undergoing startup activities, which led to flaring at the hydrogen flare. Operations brought the hydrogen-consuming units back online which then ended the flaring event.	Flaring cannot be prevented when there is insufficient hydrogen consumption due to facility and relief system design.
July 8, 2022	On July 8, 2022, Hydrogen Plant Train 1 shut down to perform repairs. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions	Flaring cannot be prevented during Hydrogen Plant shutdown due to facility and relief system design. Operational activities were consistent with shutdown procedures.
July 16-17, 2022	On July 16, 2022, Hydrogen Plant Train 1 started up following the plant shutdown. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
July 19-20, 2022	On July 19, 2022, Hydrogen Plant Train 2 shut down to perform maintenance. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely	Flaring cannot be prevented during Hydrogen Plant shutdown due to facility and relief system design. Operational activities were consistent with shutdown procedures.

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	proceeded with the shutdown activities per the procedure to reduce the emissions.	
July 23-24, 2022	On July 23, 2022, Hydrogen Plant Train 2 started up following the previous plant shutdown. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
August 2, 2022	<p>On August 2, 2022, a unit was starting up in the Distillation and Reforming Area Business Unit (ABU). The start-up procedure routes hydrogen from one unit to another. However, the procedure did not specify the line in which the hydrogen will be routed. This resulted in the hydrogen being routed down a line with a closed valve, which caused pressure to increase in the unit. Process gas was routed to the Flare Gas Recovery (FGR) System to reduce the system pressure. Gas flows to the FGR system exceeded FGR capacity, and flaring occurred. Operations opened the closed valve, and this successfully lowered the pressure in the unit.</p> <p>While hydrogen was successfully routed to other units, the rate of hydrogen sent to the Utilities and Environmental Area Business Unit (U&E ABU) caused a variation in the energy content (BTU) to the boilers at an on-site power plant. This variation in energy content caused the boilers to shut down. As a result, process steam became unavailable. This loss of steam led to a slow-down of a compressor in the Cracking ABU and increased system pressure. Process gas was routed to the FGR system to reduce the system pressure. Gas flows to the FGR system exceeded FGR capacity, and flaring occurred. Operations responded by restarting the boilers, which re-established process steam</p>	Update startup procedure to specify hydrogen routing

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	<p>production. This allowed the compressor to re-establish normal operation and normalize pressure.</p> <p>Both of these events contributed to the flaring during this time. The associated responses stopped the flow to the relief system, and the flaring ceased.</p>	
August 18-19, 2022	<p>On August 18, 2022, a unit was starting up in the Distillation and Reforming Area Business Unit (ABU). Level instrumentation on a vessel upstream of a compressor knockout drum was not in service when the startup was initiated. As the startup proceeded, liquid began accumulating in a compressor knockout drum, which Operations was not aware of due to the offline level instrumentation. As a result of increased liquid accumulation and potential for liquid carryover, a downstream compressor automatically shut down causing an increase in system pressure. Flows were then routed to the Flare Gas Recovery (FGR) system to reduce the system pressure. Flows to the FGR system exceeded FGR capacity, and flaring occurred. Operations responded by stabilizing the liquid accumulation at the compressor knockout drum, which allowed the compressor to successfully start up. This stopped the flow to the relief system, and the flaring ceased.</p>	<ol style="list-style-type: none"> 1. Update procedure to ensure level instrumentation at the vessel is in service prior to unit startup. 2. Add training on startup procedure to turnaround plan.
August 23, 2022	<p>On August 23, 2022, the Hydrogen Plant was starting up draft fans. During this process one of the Hydrogen Plant trains shut down as designed when the combustion air flow rate to the draft fans went below the system setpoint. Operations timely proceeded with the shutdown activities per the procedure to reduce the potential for increased emissions. Hydrogen Plant</p>	<p>Flaring cannot be prevented during Hydrogen Plant shutdown due to facility and relief system design. Operational activities were consistent with shutdown procedures.</p>

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	shutdown procedures include routing flows to relief and subsequent flaring.	
August 24-25, 2022	On August 24, 2022, one of the Hydrogen Plant trains attempted to start up. Startup was not successful due to a tube leak discovered at a cooling water exchanger. Operations subsequently shut down the Hydrogen Plant Train. Operations repaired the leak which allowed the Hydrogen Plant Train to restart.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures
September 7, 2022	On September 7, 2022, Hydrogen Plant Train 2 started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
September 8, 2022	On September 8, 2022, pressure swing adsorption (PSA) units were being brought online at the Hydrogen Plant. During this process, valves out of alignment at a compressor caused Hydrogen Plant train 1 to shut down. Operations timely proceeded with the shutdown activities per the procedure to reduce the potential for increased emissions. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring.	1. Update PSA startup procedure to include step to verify valves are aligned. 2.Re-align valves for Hydrogen plant startup.
September 9, 2022	On September 9, 2022, Hydrogen Plant Train 1 started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
September 12, 2022	On September 12, 2022, a compressor shut down in the Hydroprocessing Area Business Unit (ABU) due to loss of oil pressure. Gases were routed to the Flare Gas Recovery System	Replaced blocked oil filter.

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	and flows to the FGR System exceeded FGR capacity, which led to flaring. Operations replaced the oil filters, which allowed the compressor to restart. This stopped the flow to the relief system, and the flaring ceased.	
September 16, 2022	On September 16, 2022, a compressor shut down in the Hydroprocessing Area Business Unit (ABU) due to a compressor seal leak. As the compressor was shutting down, incorrect logic of the safety instrumented system caused the plant to be depressurized. Gases were routed to the Flare Gas Recovery System and flows to the FGR System exceeded FGR capacity, which led to flaring. Operations safely depressurized the plant, and the flaring ceased.	Update logic of the safety instrumented system.
October 14, 2022	On October 14, 2022, Operations was shutting down a pressure swing adsorption (PSA) unit at the Hydrogen Plant for maintenance activities. Relief flows were routed to the Hydrogen Plant relief system which does not have flare gas recovery. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions.	Flaring cannot be prevented during PSA shutdown due to facility and relief system design. Operation activities were consistent with shutdown procedures.
December 20-21, 2022	On December 20, 2022, a pump shut down in the Hydroprocessing Area Business Unit (ABU). The spare pump came online but also shut down. The faulty pumps caused hydrocarbon accumulation in the Flare Gas Recovery (FGR) system. In response to the accumulation of hydrocarbon and to prevent further disruption to refinery operations, flare gas recovery capacity was reduced, which caused flaring to occur. Operations worked to remove hydrocarbons from the FGR system and bring the pump back online, and the flaring ceased.	<ol style="list-style-type: none"> 1.Preventative maintenance performed on pumps to monitor vibrations and swap pumps targeted every 30-60 days 2.Pump was repaired and put back in service 3.Complete repair of spare pump

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December 28, 2022	On December 28, 2022, high levels of hydrocarbons in the Flare Gas Recovery (FGR) system resulted in liquid accumulation in a compressor knockout drum. Due to the increased liquid accumulation in the compressor knockout drum and potential for liquid carryover, a downstream compressor automatically shut down causing an increase in system pressure. Flows were then routed to the Flare Gas Recovery (FGR) system to reduce the system pressure. Flows to the FGR system exceeded FGR capacity, and flaring occurred. Operations responded by stabilizing the liquid accumulation at the compressor knockout drum, which allowed the compressor to successfully start up. This stopped the flow to the relief system, and the flaring ceased.	<ol style="list-style-type: none"> 1.Preventative maintenance performed on pumps to monitor vibrations and swap pumps targeted every 30-60 days 2.Pump was repaired and put back in service 3.Complete repair of spare pump
March 05, 2023	On March 05, 2023, Hydrogen Plant Train 1 started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures
March 07, 2023	On March 07, 2023 Hydrogen Plant Train 2 started up. Hydrogen plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures
March 08, 2023	On March 08, 2023 Hydrogen Plant train 1 was shut down. Operations timely proceeded with the shutdown activities per the procedure to reduce the potential for increased emissions. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures
March 09 – 10, 2023	On March 9, 2023, while Hydrogen Plant Train 1 was offline for maintenance, Hydrogen Plant Train 2 lost power due to a ground fault on a boiler feedwater pump motor. The ground fault caused	Faulty boiler feedwater pump motor. The was due to corrosion from water intrusion, as well as incorrectly

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	a loss of power to the two electrical buses located in the common substation, resulting in the loss of critical equipment and an operator-initiated emergency shutdown of Hydrogen Plant Train 2. In response, hydrogen consumers in the Hydroprocessing Area used emergency procedures to pull feed and depressurize systems, which resulted in flows to the Flare Gas Recovery (FGR) system. Flows to the FGR system exceeded FGR capacity, and flaring occurred. The faulty motor was isolated from the rest of the system. Per procedure, personnel verified the safe condition of all other electrical equipment at the Hydrogen Plant and determined that Hydrogen Plant Train 2 was safe to restart. The other impacted refinery process units subsequently started up after hydrogen production was available.	ranged pressure gauge on the motor and excessive air filter pressure
March 09, 2023	On March 09, 2023, the faulty feed boiler pump motor caused a loss of power to the two electrical buses located in the common substation resulting in the loss of critical equipment and an emergency shutdown of Hydrogen Plant Train 2. Operations timely proceeded with the shutdown activities per the procedure to reduce the potential for increased emissions. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures
March 10-11, 2023	On March 10-11, 2023, Hydrogen Plant Train 2 started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures
March 12-13, 2023	From March 12, 2023, through March 13, 2023, Hydrogen Plant Train 2 started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design.

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	proceeded with the startup activities per the procedure to reduce the emissions.	Operational activities were consistent with startup procedures.
March 19, 2023	On March 19, 2023, Hydrogen Plant Train 1 started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Flaring cannot be prevented during Hydrogen Plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
April 15-17, 2023	Hydrogen Plant train 2 started up from April 15, 2023 to April 17, 2023. Hydrogen Plant startup procedures include routing hydrogen flows to the dedicated flare. Operations timely proceeded with the startup activities per the procedure to reduce the emissions	Flaring cannot be prevented during Hydrogen plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
May 16-17, 2023	A Hydrogen Plant Train shut down from May 16, 2023 to May 17, 2023. Hydrogen Plant shutdown procedures include routing hydrogen flows to the dedicated flare. Operations timely proceeded with the shutdown activities per the procedure to reduce any emissions.	Flaring cannot be prevented during Hydrogen plant shutdown due to facility and relief system design. Operational activities were consistent with startup procedures.
May 19, 2023	On May 19, 2023, a Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce any emissions.	Flaring cannot be prevented during Hydrogen plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
June 14, 2023	On June 14, 2023, a Hydrogen Plant Train was started up. Hydrogen Plant startup procedures including routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce any associated emissions	Flaring cannot be prevented during Hydrogen plant startup due to facility and relief system design. Operational activities were consistent with startup procedures.
July 17, 2023	On July 17, 2023, residual brine, which was supposed to be rinsed out through the rinse valve, within the steam system's water softeners caused high total dissolved solids (TDS) in the water that feeds to a steam generator. The elevated TDS caused foaming in the steam generator and subsequent level	Shutdown of hydrogen recycle compressor due to the residual brine in the boiler feed water system.

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	swings, causing wet steam to carry into the 150-pound steam system. This caused a steam driven hydrogen recycle compressor to reduce speed. While attempting to speed the compressor back up, the operating plant's furnaces tripped offline on low recycled hydrogen flow and resulted in an increased temperature within the associated reactors. A safety device was then activated to route vent gas to the flare system.	
July 17-18, 2023	On July 17, 2023, a flare gas recovery compressor shut down due to the false indication of high temperature on the temperature indicator. This caused flow to be routed to the flare system.	Shutdown of a flare gas recovery (FGR) compressor
August 13, 2023	On August 13, 2023, a Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Startup of Hydrogen Plant Unit Train while adhering to unit procedures
August 21, 2023	On August 21, 2023, low pressure boiler feedwater (LPBFW) to operating plants was lost during an attempted cutover to a temporary LPBFW system due to a pump failure. The loss of LPBFW caused a reduction of pressure to the 150-pound steam header, subsequently causing a reduction of power to the recycle gas compressors. The reduction in recycle flow required the use of a depressurizing system, sending gas to the flare to ensure safe reactor temperatures.	The pump governor's drive coupling materials did not meet manufacturer's service life that led to premature failure of the pump governor which resulted in the failure of the pump
November 14, 2023	On November 14, 2023, Hydrogen Plant Trains shut down then started up later on the same day. Hydrogen Plant shutdown and startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown and startup activities per the procedure to reduce the emissions.	Shutdown of Hydrogen Plant Unit Train while adhering to unit procedure
November 15, 2023	On November 15, 2023, the startup of Hydrogen Plant Train 2 continued. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely	Startup of Hydrogen Plant Unit Train while adhering to unit procedures

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	proceeded with the startup activities per the procedure to reduce the emissions.	
November 17, 2023	On November 17, 2023, Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Startup of Hydrogen Plant Unit Train while adhering to unit procedures
November 27, 2023	The Refinery's electrical system, like many other critical equipment systems within the facility, are designed with redundancies that help ensure continual operation in the event of a malfunction or routine maintenance. On 11/27/2023, at approximately 11:30am, an electrical line feeding a portion of the facility tripped open, eliminating the designed electrical redundancy, or backup power, to a segment of the facility. Personnel were dispatched to identify the root cause of the electrical line failure so that power could be restored to the redundant system. During this time, facility operations were not impacted as the secondary electrical line feeding the same systems was still operational. At 3:25pm, during the inspection of the electrical line failure, the secondary power line experienced a failure. Power was unexpectedly lost, impacting a portion of the facility. The loss of power resulted in the activation of the facility's safety systems and significant visible flaring. Operations personnel worked quickly to stabilize the impacted operating equipment to minimize and eventually stop the flaring event.	Electrical equipment (i.e., an auxiliary relay) did not operate as designed. During a visual inspection, the relay improperly self-activated and tripped the electrical banks causing a complete loss of power to the substation that led to a shutdown of Hydroprocessing units causing the flaring event.
November 27, 2023	On November 27, 2023, Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Startup of Hydrogen Plant Unit Train while adhering to unit procedures
November 28, 2023	On November 28, 2023, Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Startup of Hydrogen Plant Unit Train while adhering to unit procedures

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November 30, 2024	On November 30, 2023, Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Startup of Hydrogen Plant Unit Train while adhering to unit procedures
December 5, 2023	Pressure in amine degasser vessel increased and lifted a pressure release device (PRD) which resulted in flows to the Flare Gas Recovery (FGR) system. Flows to the FGR system exceeded FGR capacity and flaring occurred.	The liquid level indicator on an upstream liquid knock-out drum was not operating correctly thereby allowing additional gas to enter the amine degasser vessel
December 31, 2023	On 12/31/2023, a Hydrogen Booster Compressor (K-900A) was taken out of service due to Hydrocom issues. Operations was attempting to start up another Hydrogen Booster Compressor (K-900) as a replacement for K-900A. During the startup process, the downstream orbit valves became malfunctioned and closed. These orbit valves have rising stems that confirm whether or not the valve is open. However, in this scenario, both valves were showing open in the field based on the indication of the stems when the valve were closed internally. The malfunctioned valves led to increased pressure upstream that lifted the pressure relief devices leading to the flaring event subsequently.	The orbit valves had failed internals and became malfunctioned.
April 9, 2024	On April 9, 2024, operations were conducting troubleshooting activities due to erratic readings of reflux flow rates. It was observed that the reflux drum's gauge glass indicator made it difficult to discern the liquid level, requiring a manual adjustment to the level controller to track any rise in level. Subsequently, the reflux drum's high-level alarm was triggered. With the level controller manually closed during troubleshooting activities, the liquid from the reflux drum carried over to the knock-out drum of the flare gas recovery compressor, causing the compressor to trip, which resulted in flaring.	Adjustment of the level controller caused liquid from the reflux drum to carry over to the KO drums

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April 29, 2024	On April 29, 2024, a crack in a feed compressor's spillback line was identified. Operations immediately swapped to the alternate feed compressor. A scheduled electrical maintenance work inadvertently cut off the alternate compressor's power supply. This mishap resulted in the temporary shutdown of the alternate compressor and subsequently flaring at the H2 flare.	Expectations regarding contacting Chevron personnel for all switches were not adequately understood by contractors.
May 16, 2024	On May 16, 2024, Hydrogen Plant Train shut down. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions.	Shutdown of Hydrogen Plant Unit Train while adhering to unit procedures
May 23, 2024	On May 23, 2024, Hydrogen Plant Train shut down. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions.	Shutdown of Hydrogen Plant Unit Train while adhering to unit procedures
May 27, 2024	During activity to prepare an operating unit for maintenance, steam is utilized, and the unit is depressured to the relief system per procedure. During this unit clean up activity, the hot steam caused elevated temperatures on the relief system's compressor valves. This resulted in the Flare Gas Recovery compressor shutting down that limited the flare gas recovery capacity and subsequently caused flaring.	Steam as part of process plant maintenance preparation, or vapor phase clean-up, caused elevated temperatures on the flare gas compressor valves
May 29, 2024	On May 29, 2024, Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Procedures are designed to adhere to unit and flare system design.
June 2-3, 2024	On June 2, 2024, a Hydrogen Plant Train shut down. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the shutdown activities per the procedure to reduce the emissions.	Procedures are designed to adhere to unit and flare system design.
June, 13, 2024	On June 13, 2024, a Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Procedures are designed to adhere to unit and flare system design.

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
August 2, 2024	On August 2, 2024, a mechanical failure occurred within the steam system associated with a recycle hydrogen compressor. The mechanical failure caused the steam system to close, shutting down the associated compressor. The loss of the recycle hydrogen stream to the process unit initiated a shutdown of the process unit and led to the flaring event.	Mechanical failure of Heim joint within the steam system
August 15, 2024	On August 15, 2024, the startup of a process unit resulted in an increased gas flow to a separation vessel, which subsequently raised the vessel pressure. The pressure increase activated the associated pressure relief devices, leading to flaring.	Opportunity to improve guidance in the startup procedure to manage high pressure alarm during startup.
February 1, 2025 ⁽ⁱⁱⁱ⁾	On February 1, 2025, during a unit startup, a flow control valve positioner failed, which led to the valve opening more than it showed on the control board, causing a pressure increase within a process unit. The pressure relief valves on the impacted unit opened to relieve the pressure, thereby resulting in the flaring event.	Mechanical failure of a control valve positioner
February 2, 2025 (i),(ii),(iii),(iv)	On February 2, 2025, a Hydrogen train tripped offline due to a failed level indicator on a hot condensate drum, which resulted in a series of level excursions. This failure resulted in low levels in several critical drums, which caused instability at the hydrogen plant. Consequently, the remaining hydrogen train also tripped. The loss of both Hydrogen trains caused a significant reduction in steam load, leading to the shutdown of multiple units within the refinery and resulting in the flaring event.	Failure of a condensate drum level indicator
February 7, 2025 ^{(i),(ii)}	On February 7, 2025, the Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations proceeded with the startup activities in a timely manner per the procedure to reduce the emissions.	Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations proceeded with the startup activities in a timely manner per the procedure to reduce the emissions.
February 8, 2025 ^{(i),(iii),(iv)}	On February 8, 2025, a malfunction occurred on a Hydrogen recycle compressor due to mechanical fatigue of the actuator linkages during startup activities in the process units. This failure necessitated pulling feed and subsequently shutting down the	Hydrogen recycle compressors failed shut due to mechanical fatigue of the actuator linkage

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
	units. As a result, the reactors had to be depressurized, which exceeded the flare gas compressor capacity and led to the flaring event.	
February 14, 2025 ^{(i),(ii)}	On February 14, 2025, the Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations proceeded with the startup activities in a timely manner per the procedure to reduce the emissions.	Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations proceeded with the startup activities in a timely manner per the procedure to reduce the emissions.
February 21, 2025 ⁽ⁱⁱ⁾	On February 21, 2025, the Hydrogen Plant Train shut down. Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations proceeded with the shutdown activities in a timely manner per the procedure to reduce the emissions.	Hydrogen Plant shutdown procedures include routing flows to relief and subsequent flaring. Operations proceeded with the shutdown activities in a timely manner per the procedure to reduce the emissions.
March 2, 2025 ^{(i),(ii)}	On March 2, 2025, Hydrogen Plant Train started up. Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations timely proceeded with the startup activities per the procedure to reduce the emissions.	Hydrogen Plant startup procedures include routing flows to relief and subsequent flaring. Operations proceeded with the startup activities in a timely manner per the procedure to reduce the emissions.
May 5, 2025 ^{(iii),(iv)}	On May 5, 2025, a Gas Recovery Unit experienced an over pressure situation that led to flaring. The process system had an increase in pressure due to faulty instrumentation requiring operations to route excess flows to the relief system. This caused the flare gas recovery compressors to shut down on high level and flaring occurred.	The level instrumentation failed due to plugging.
May 22, 2025 ^(iv)	On May 22, 2025, a heat exchanger got plugged and caused a pressure increase in the first stage discharge line. The pressure increase activated the pressure relief device and shut down the compressor causing the flaring event.	The water wash system was out of service causing heat exchanger plugging.
May 31, 2025 ^{(iii),(iv)}	A pump within a process unit was being returned to service. During this process, lighter density oil was introduced as the pump was warming up to clear a hydrocarbon blockage that occurred within the pump system. As the hydrocarbon blockage cleared, conditions allowed this lighter oil into the common	Lighter density oil (Medium Cycle Oil or MCO) migrated through suction valves that were not fully closed due to a malfunctioning engagement between the valve gate and the valve seat.

<i>Date</i>	<i>Description of Activity Resulting in Flaring that Required Causal Analyses</i>	<i>Lessons Learned</i>
	header of the pump system where it vaporized causing an upset in the pumps system, as well as the associated process column and related equipment. As a result, the process unit was shutdown, gases from the impacted unit were routed to the relief gas system, and visible flaring occurred.	
June 6, 2025	On June 6, 2025, PSA 3 at the Hydrogen Plant tripped offline due to a malfunction of a pressure indicator. The indicator faulted to high scale, which caused the trip. The unit was stabilized and the pressure indicator was replaced. The unit was restarted on June 7, 2025 at about 1:42 and flaring during start-up lasted 8 minutes.	Malfunction of a pressure indicator that could not be foreseen.

Notes:

- (i) 5 largest flaring events based on flared vent gas volume for the current reporting year*
- (ii) 5 largest flaring events based on Methane (CH₄) emission for the current reporting year*
- (iii) 5 largest flaring events based on Non-methane Hydrocarbon (NMHC) emission for the current reporting year*
- (iv) 5 largest flaring events based on Sulfur Dioxide (SO₂) emission for the current reporting year*

5.1.5 Measures to Minimize Flaring During Planned Maintenance

The Richmond Refinery has identified practices to minimize future flaring during planned maintenance activities. Specific lessons learned from recent shutdowns are shown above, in Table 5-1. These and other possible measures are also described below in more detail.

These possible measures are applied in several different manners. Maintenance of pressure relief devices to API Standard 510 is performed on a continual basis according to a set interval for each device. Flare gas recovery compressors are maintained according to weekly and/or continuous monitoring. (See also Section 2.1.) The applicability of each of the other possible measures highlighted below would be evaluated as part of the IMPACT planning process to minimize or eliminate flaring on a case-by-case basis. (See Section 5.1.6 for the IMPACT process.)

Lessons learned from the IMPACT process can include the considerations for recovery in Section 5.2.4. Gases are routed to FGR compressors as long as the heat generated by compressing these gases does not exceed the discharge temperature of the compressor, which could cause damage to the compressor and ultimately result in flaring due to the loss of FGR compressor operation. Additionally, the feasibility of providing additional compression, storage, and treatment options was looked into as a part of the assessment of measures to prevent flaring. These options were determined to be infeasible based on costs. Section 5.2.4 addresses options for flare gas recovery, treatment and re-use. Chevron examined the feasibility of performing each of the major maintenance activities below without flaring. As a result of this examination, the following measures were determined:

Hydroprocessing

High pressure units are first depressurized to a suitable process location (such as the hydrogen recovery unit), or other lower pressure location, and only after this are they depressurized to the relief system, reducing the load on the flare gas recovery system.

Following the initial depressurization, the remaining hydrocarbon is removed by increasing the pressure in the equipment with nitrogen and then depressurizing it to the relief system multiple times. Performing the depressurization quickly helps with mixing, which improves the efficiency of hydrocarbon removal from the vessel so that fewer overall cycles of purging and depressurization are needed.

In the RLOP 2011 shutdown, a temporary steam condenser was used and the process gas flows to relief generated by the RLOP maintenance activity was isolated from FGR in order to allow the remaining NY plants to stay on FGR without overwhelming the systems and causing further flaring. Employing these techniques successfully decreased flaring during major maintenance activity and will be incorporated into IMPACT planning process for future maintenance turnarounds.

Cracking

Specific improvement opportunities based on the FCC 2005 shutdown were incorporated into the FCC 2010 shutdown, which successfully decreased flaring during major maintenance activity. The techniques used in the FCC 2010 shutdown will be incorporated into IMPACT planning process for future maintenance turnarounds.

Chevron will consider and implement feasible prevention measures, including extending purge sequences when consistent with safe and reliable operations, to reduce emissions and minimize impacts on the relief system by avoiding overloading of the available flare gas recovery system capacity.

Catalytic Reformer

Prior to performing maintenance, low sulfur process gases are depressurized directly to the refinery's fuel gas system rather than to the relief header and flare gas recovery system.

The timing of the (periodically conducted) regeneration cycles is controlled, and the venting / depressurizing rate is limited to be within the available capacity of the flare gas recovery system.

Furnaces Pass Tubing

When vertical furnace pass tubes are to be cleared of hydrocarbon (which can accumulate at the low points of the tube bends) by blowing with nitrogen, the duration of nitrogen flows can be minimized by first inspecting each of the tube passes and making adjustments to the standard recommended nitrogen blowing times.

The duration of the nitrogen blowing can be minimized to be within the available capacity of the flare gas recovery system.

Depressurization

Alternate "routes" for depressurization of equipment are used so that routing gas through the relief header and flare gas recovery system is not necessary if the gas is at pressures sufficient for direct routing to the treating plant, or, for gases not requiring sulfur removal, to another process unit or into the refinery's fuel gas system.

This would eliminate gases from impacting the flare gas recovery system generated by depressurization of certain plants within the Refinery.

Pressure Relief

Maintenance, inspection and servicing of Pressure Relief Devices (PRDs) is carried out according to Refinery Instruction 609 (RI-609), which summarizes requirements in American Petroleum Institute (API) Standards 510 and 570, API Recommended Practices 520 and 576, National Board Inspection Code (NBIC), and California Code of Regulations Title 8, Chapter 4, Subchapter 1, 2, and 15. This refinery instruction establishes policies for servicing, testing, and recordkeeping of PRDs that protect pressure vessels, piping, and other equipment. RI-609 ensures that proper service intervals for PRDs are established and followed, and that PRDs are properly serviced and tested. The use of RI-609 minimizes flaring by optimizing intervals for testing of PRDs and inspection, thus reducing impacts to the relief system. In addition, ensuring PRD reliability results in fewer malfunctions and therefore less likelihood for flaring.

Flare Gas Recovery Compressors

The operating temperatures of the flare gas recovery compressors are monitored, so that relief gases may be diverted away from the flare gas compressor only when outside of the range that the compressors can safely handle.

Process unit compressors (e.g., K1960 in the North Yard, K-1171/K-1171A and K-242/252 in the South Yard) with spare capacity are configured for optional use in flare gas recovery service. The regular flare gas compressors are part of a utility system and need to be online except during maintenance or when not needed for capacity reasons.

Flare gas compressors are maintained during periods of minimum capacity needs and/or following planned process unit shutdowns in the areas they serve, so there are fewer issues during periods of normal operation. A planned shutdown provides an opportunity to do maintenance, since relief gas loads from the inoperative plant are not entering the system.

Regular preventative maintenance of flare gas compressors is used to improve their reliability.

Shutdown/Startup planning & Shutdown Procedures

A shutdown flare plan is developed for each turnaround with a scope that results in a greater potential for flaring. The plan identifies possible sources of flaring and incorporates some choices of action for the turnaround that can minimize flaring. Each plan is unique to the planned activity for a particular turnaround. Specific actions planned for the turnaround depend on which parts of the unit are being brought down and which other units are also down at the same time.

Equipment is purged at a rate which will remove hydrocarbons to allow access for maintenance and minimize impacts to the relief system by avoiding overloading of the available flare gas recovery system capacity. Following the initial depressurization, the remaining hydrocarbon is removed by increasing the pressure in the equipment with nitrogen and then depressurizing it to the relief system multiple times. Performing the depressurization quickly helps with mixing, which improves removal of hydrocarbon from the vessel so that fewer overall cycles of purging and depressurization are needed. This is scheduled as part of the IMPACT planning process. See Section 5.1.6 for the IMPACT process. Clean-up activities are planned and scheduled as part of the IMPACT planning process to minimize impacts of nitrogen flows to the relief system.

General

For connected flare systems, such as in the refinery's North Yard Flare Gas Recovery System, plant areas generating relief gases that cannot be recovered can be isolated from the rest of the flare gas recovery system. By isolating a plant area, and diverting only that flow to a flare, gases from other plant areas can continue to be recovered for treatment and use in the refinery's fuel gas system.

5.1.6 Turnaround and Maintenance Flare Minimization Planning Tool

The Richmond Refinery's existing flare planning process has been expanded to incorporate a broader range of planned refinery activity, which includes short term planned maintenance. The expanded scope of the relief planning process captures additional opportunities for flare minimization. Lessons learned to minimize flaring are captured and considered during future planned turnaround and maintenance events.

Per the IMPACT planning process for maintenance turnarounds a flare plan is prepared as part of the turnaround planning process. This plan identifies a schedule of discrete work steps such as pulling feed, shutting down, depressurizing, and cleaning up units and equipment that could generate flare gas to relief. Impacts to the relief system are predicted and estimated by using parameters such as sulfur content, flow rate and duration. A most-likely case and worst-case scenario is usually developed for each step having an impact. Consideration is given to whether relief gases can be recovered or routed to another location besides relief. Whenever applicable, the depressurization / purging duration and rate are decreased to keep the vent gas flow under FGR capacity.

The development of flare plans under IMPACT SCS Task No. 27 is joint effort between the turnaround Operations Coordinator, Plant Process Engineer, and the IMPACT Planner. The improvements to this procedure are shown in figure 5-1 and listed in table 4-1.

Inputs into the plan include:

- Major operating steps involving depressurizing or relieving equipment to relief, nitrogen purging to the flare and shutdown/startup of flare gas recovery systems.
- Environmental or regulatory limits and internal guidelines and limits for depressurizing equipment to relief or operation of the flares.
- Current sources and typical rates of gas to the relief system, current typical Flare Gas Recovery system rates and total FGR system capacity.
- Expected post-shutdown sources and typical rates of gas to the relief system, expected FGR system rates, and expected FGR system capacity.

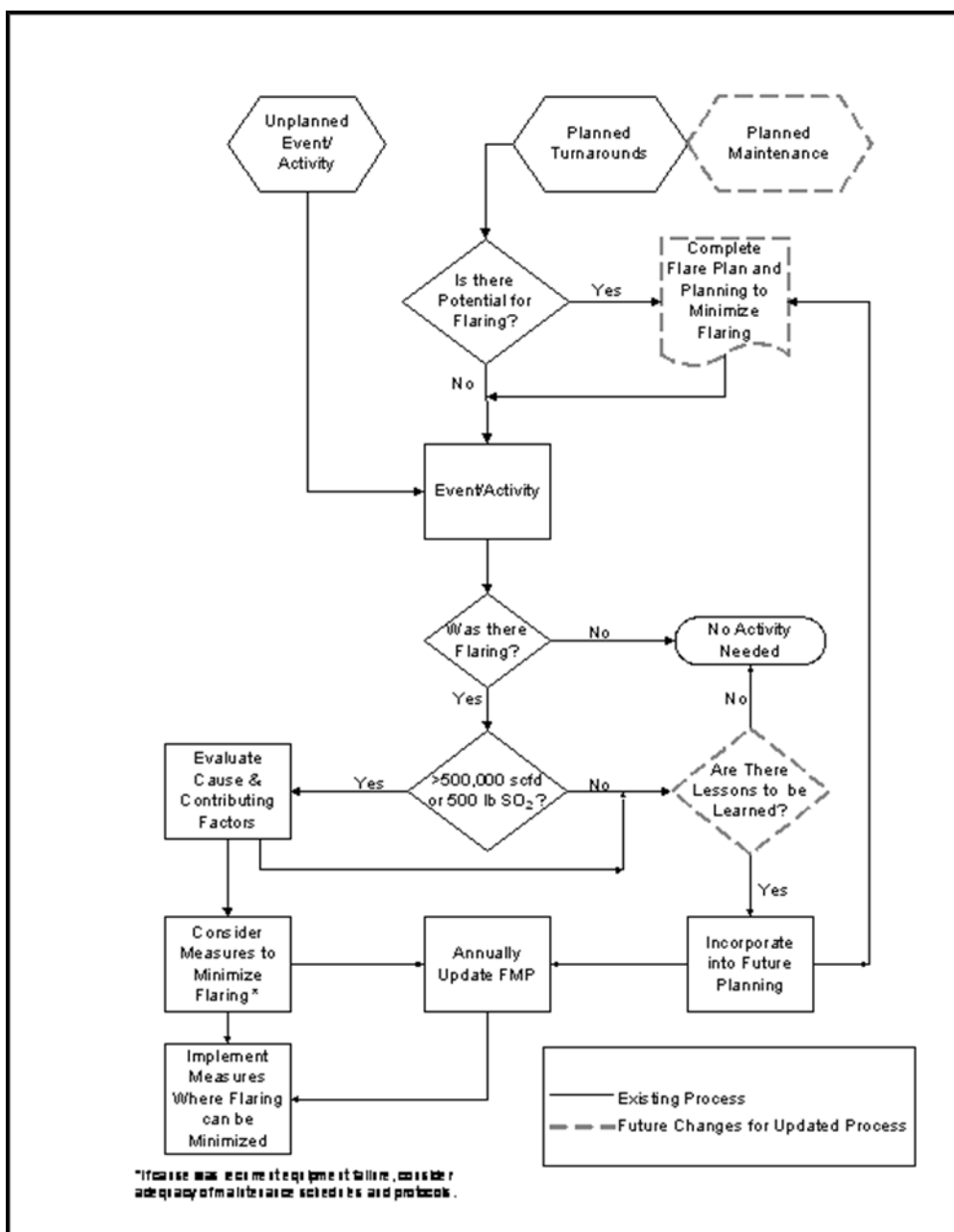
Plan outputs include a schedule of all equipment depressurized to flare during shutdown, clean-up and start-up of the unit. The plan shall meet all regulatory and management limits on depressurizing equipment to relief and operation of the flare. The schedule is routed to Environmental and Process Engineering Groups as needed.

The IMPACT process for planning major maintenance turnarounds includes a "lessons learned" session to incorporate learnings into the next subsequent turnaround. The Refinery has developed a process to formalize the "lessons learned" process in order to capture and document learnings. This process happens approximately 18-24 months before pulling plant feed. Lessons learned can include the considerations for recovery in Section 5.2.4.

5.1.7 Measures to Minimize Flaring During Unplanned Maintenance

There are occasions, primarily as a result of equipment malfunction, where a relatively immediate decision is made to shutdown a block of the refinery, typically within a period of days, allowing little time for the kind of specific planning used for turnarounds and planned maintenance. In these cases, it is often not possible to make the same level of plant adjustments necessary to minimize flaring to the extent possible when a shutdown is planned far in advance. Despite this, there are actions that can be taken to minimize flaring even when there is very little advance notice. For these cases, the refinery utilizes general procedures to minimize flaring for unplanned events, as shown in Figure 5-1. Although there is less of an opportunity for scheduling shutdown procedures so as to ensure that there will be a home for all of the gas generated at each step of the process, many of the same general principles apply when the decision to bring the unit down is immediate. A flowchart of the Richmond Refinery's Flare Planning process is shown below, in Figure 5-1. This flowchart identifies aspects of the existing process, and highlights areas that will be updated.

Figure 5-1, Flare Planning Process Flowchart



5.2 Gas Quality and/or Quantity Issues

Pursuant to the requirements of Regulation 12, Rule 12, Section 401.4.2, this section provides a description and evaluation of prevention measures for flaring that may reasonably be expected to occur due to issues of gas quantity or quality. The section includes information on when flaring is likely to occur, as well as a discussion of the refinery's systems for recovery of relief gases. An evaluation of options for increased recovery, storage, and treatment of gases is also presented.

Fuel gas is generated in varying quantity and quality from the following process units: FCC; TKC; TKN; ISO; LNF; HNF; RLOP; FGR; NHT & JHT. All of these gas streams have high H₂S content, and these streams are scrubbed to remove the H₂S before they are sent to the refinery fuel gas (RFG) header. The Refinery has two separate, but interconnected, fuel gas headers are operated that serve the two main process areas, North Yard and South Yard. RFG is used as feed to the Hydrogen trains or as refinery fuel in process heaters on the units and the Cogen.

RFG is a mixture of natural gas and sweetened process gas from the refinery H₂S Plants and vaporized LPG (primarily C₄). The following composition and characteristics are approximately typical of RFG:

Hydrogen	14.0
Methane	58.8
Propane	8.0
Butane	9.0
C ₅ +	1.0
Nitrogen	3.0
CO ₂	0.2
High Heating Value	1,100 Btu/SCF
Low Heating Value	1,000 Btu/SCF
Specific Gravity	0.67
H ₂ S Content	160 ppm max

The quantity and quality of the fuel gas will vary depending on the type of crude oil being processed, the severity of operations, and the relative contributions from the various process units at any one time.

In normal operations, the RFG is supplemented with fuel from both natural gas (NG), Medium BTU Gas (MTG) and Liquid Petroleum Gas (LPG). The blend of these supplementary fuels depends on the heat content of the RFG, the refinery demand, and the supplies of material from these other sources. Because in normal mode there is not sufficient RFG thermal heating value for all users, and as a safety provision that critical equipment is not solely dependent on a single fuel source, it is necessary to supplement the RFG with imported natural gas (NG).

Fuel gas drums are monitored for heating value, specific gravity, pressure and H₂S on a continuous basis. Hourly averages for heating value, specific gravity and pressure are reviewed on a daily basis. All fuel gas drums alarm if the instantaneous value of the H₂S reaches 50 ppm. Computer monitoring analyzes and adjusts the RFG, NG, MTG, and LPG continually to maintain an efficient balance. Maintaining the right RFG composition is critical from an efficiency and safety perspective, as:

- Not optimizing RFG use means either importing extra NG or vaporizing valuable LPG product.

- Having too much RFG with low heating value content (such as H₂, N₂ or CO₂) can lead to severe operational problems that include flame instability, operating equipment outside the manufacturer's suggested operational range for the burners, flame lift off forcing a plant shutdown, incomplete combustion causing high CO and hydrocarbon situations, and in worse case scenarios, detonation of un-burnt hydrocarbons in the furnace. An unplanned, emergency shutdown due to RFG with an overall heating value that is too low is an unacceptable risk because it causes additional flaring during a plant shutdown as well as exposes personnel to an unacceptable operating condition in the furnace boxes.
- Increased quantity of RFG with low heating value content can lead to poor flame patterns, causing potential reliability issues such as burner wear or tube impingement.

5.2.1 When Flaring is Likely to Occur due to Gas Quality/Quantity Issues

Richmond Refinery has identified situations or activities likely to cause flaring, as described below in more detail. Releases of relief gas to the flare result from an imbalance between the quantity of vent gas produced by the refinery and the rate at which it can be compressed, treated to remove contaminants (sulfur compounds) and utilized as fuel gas. Situations that can lead to flaring can be grouped together based on similarity of cause. These general categories, including some specific examples of events which fit into each category, are outlined and discussed below:

Maintenance Turnaround, Startup and Shutdown

To prepare an individual equipment item or a block of refinery equipment for maintenance, it is necessary to isolate it from active operations and clear it of process fluids. Examples include:

- Unit shutdowns
- Working on equipment and/or relief systems
- Catalyst change
- Plant leak repairs
- Compressor maintenance or repairs

In order to avoid flaring there must be a balance between producing and consuming fuel gas units. When either a block of equipment or an individual equipment item is removed from service, if it either produces relief gases or consumes fuel gases, then the balance of the fuel gas system is changed and adjustments are necessary to bring the system back into balance. If the net change in gas production or consumption is large and the adjustments in the rate at which gas is produced or consumed by other units cannot be made quickly enough, then flaring results. Examples include:

- Hydrogen Plant (Furnaces) Shutdown
- Startup of the TKN/ISO Gas Recovery Unit
- Startup of FCC unit and/or shutdown of the Alkylation unit

Additionally, in order to clear hydrocarbons from equipment in a safe and controlled manner prior to performing maintenance, a variety of procedures must be used. These procedures can change the quantity and quality of fuel gas produced. Examples include:

- Depressurization of equipment
- Pressurization of equipment with nitrogen to remove hydrocarbon resulting in low fuel value (high nitrogen content) gas which cannot be used with burners designed for "normal" flare gas, as NO_x issues with low Btu gas.

Upset/Malfunction

An imbalance in the flare gas system can also result from upsets or equipment malfunctions that either increase the volume of flare gas produced or decrease the ability of the fuel gas handling system to accommodate it. Examples include:

- Leaking relief valves
- Pressure Relief Valve malfunction
- Equipment overpressure or other cause for relieving relief valves
- Equipment Plugging resulting in local overpressure
- Loss of a major process unit compressor (e.g., FCC wet gas compressor)
- Loss of fuel gas recovery system compressors
 - Reciprocating compressor seats overheating from high nitrogen or hydrogen content
 - Fuel gas with low specific gravity, or high heat of compression resulting in overheating
 - High inlet temperature to flare gas compressor
 - General mechanical problems from the operation of rotating equipment.
- Loss of a utility (steam, cooling water, power)
- Loss of air fins or condensers

Emergencies

Pursuant to Regulation 12, Rule 12, Section 201, an emergency “is a condition at a petroleum refinery beyond the reasonable control of the owner or operator requiring immediate corrective action to restore normal and safe operation that is caused by a sudden, infrequent and not reasonably preventable equipment failure, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility.”

Other Causes

There are many potential other causes of flaring which cannot be eliminated, despite careful planning and system design to minimize the risk of their occurring. Some examples of these types of other causes include:

- Sudden, infrequent and not reasonably preventable equipment failures
- Shutdown
- Start-up
- Acts of God
- Terrorism

5.2.2 Vent Gas Recovery Systems

Refinery unit operations both produce and consume light hydrocarbons. Most of these hydrocarbons are routed directly from one refinery process unit to another. Refineries are constructed with a network of relief gas headers running throughout each of the process units in order to allow collection and safe handling of any hydrocarbon vapors that cannot be routed directly to another process unit. The hydrocarbon vapors are collected at low pressures in these relief gas headers. These gases are recovered for reuse by increasing their pressure using a flare gas compressor system. The compressed gases are typically returned to the refinery fuel gas system for use in fired equipment within the refinery. Any gas not compressed and sent to the fuel gas system is routed to a flare so it can be disposed of safely by combustion under controlled conditions. A typical flare gas system was shown at the beginning of this document, in Figure 1-1. Schematic diagrams of the specific flare gas recovery systems in place at the Richmond Refinery are provided in Appendix A.

The capacity of a flare gas recovery system is functionally the total capacity of the FGR compressors (aside from spares). As long as the FGR load does not exceed the capacity of the current FGR compressors, and the compressors are reliable, there is no benefit to running spare compressors or installing larger machines, as is shown on Table 5-3. Where spare units are provided that are not operated simultaneously, the spare capacity is not included as a part of total system capacity. Flare gas compressor capacity does not fully define the total capacity of the system in all cases, however. To recover flare gas for use in the fuel gas system, three criteria must be met. First, there must be sufficient flare gas compressor capacity. Second, there must be sufficient gas treating capacity. Finally, there must either be available storage volume or a user (e.g., fired heater) with a need for the gas. If any of these conditions are not met, then the gas cannot be recovered into the fuel gas header.

5.2.3 Existing Systems for Vent Gas Recovery

Within the Richmond Refinery, the systems that currently exist for recovery and treatment of vent gases, and the typical scenario for their use, are described in Table 5-2 below.

Table 5-2 Flare Gas Recovery System Capacities

<i>Flare System</i>	<i>Vent Gas Recovery (Compressor) Capacity (MMSCFD)</i> Notes 3,4	<i>Storage Capacity (MMSCF)</i>	<i>Amine Plant Inlet Capacity (MMSCFD)</i> Note 5	<i>Sour gas production from process units (MMSCFD)</i> Note 6	<i>(Amine plants) Scrubbing Capacity for Vent Gas (MMSCFD)</i>
North Yard – #3H2S Plant	n/a	n/a	25	25	0
North Yard – #4 H2S Plant	8	n/a	25	45	0
North Yard – #6 H2S Plant	Note 7				
South yard – #5H2S Plant	2 – 6	n/a	40	10	10
Totals	10 – 14	n/a	90	80	10

Note 3: Where spare equipment has been installed, the capacity shown is exclusive of the installed spare equipment and includes only the capacity that can be achieved when all equipment which could reasonably be operated simultaneously is online.

Note 4: The South Yard Flare Gas Recovery System has the option to put K-1171/K-1171A and K-242/252 compressors into service to augment capacity of the main K-3950 Flare Gas Recovery Compressor.

Note 5: The Amine (H2S Treating) plants are also subject to, and may be limited by, Title V back-end throughput limits on the volumetric rate of H2S production.

Note 6: This column shows typical sour gas production rates. Note that the North Yard can export up to 20 MMSCFD sour gas to the South Yard and process this gas in the #5 H2S Plant.

Note 7: #6 H2S Plant is part of the Chevron Refinery Modernization Project. The plant is not currently in operation.

The Richmond Refinery vent gas recovery system does not include any dedicated capacity for storage of fuel gas or vent gas. However, on a continuous basis the refinery optimizes the refinery fuel gas system of producing and consuming units to maximize the capacity available for treatment and reuse of recovered gases by employing the following strategies:

- adjusting the sources of fuel that are made up to the fuel gas system including imported natural gas, propane, and butane;

- adjusting the operations of units that produce fuel gas range materials including at times reducing severity of operations to reduce fuel gas production if it places the refinery in a flaring situation; and
- adjusting the refinery profile for consumption of fuel gas by ensuring that fuel gas consuming units and/or equipment are being used to full extent possible, e.g., shifting rotating equipment to turbine drivers where available as spares (which operate with steam generated in the fuel gas fired boilers).

The total gas scrubbing capacity that is indicated is an integral part of the refinery fuel gas management system. This capacity is closely matched with the fuel gas consuming units (e.g., heaters, boilers, etc.) usage requirements. The capacity indicated as being available for recovered vent gas scrubbing will vary depending on the balance between fuel gas production and consumption; it will vary both on a seasonal basis and during the course of the day. For this reason the table above provides the approximate nominal available capacity.

With this system for flare gas recovery in place, the combined daily average flow recovered by the North and South Yard Flare Gas Recovery Systems was 5.27 MMSCFD during the 2005 calendar year, equivalent to an annualized total of approximately 1923 MMSCF per year. The total of vent gases flared during the 2005 year was approximately 142 MMSCF. This shows that the vent gas recovery system effectively recovered and reused 93% of the volume of gases routed to the relief gas headers.

5.2.4 Options for Recovery, Treatment and Use

To address the requirements of Regulation 12, Rule 12, Section 401.4, the Richmond Refinery has considered the feasibility of further reducing flaring through additional recovery, treatment, and/or storage of relief gas header gases, or through other means to use the recovered gases. This evaluation considers the impact these additional systems would have on the volume of flared gases remaining in excess of what has already been recovered (as noted in the previous section), and the associated mass flow of hydrocarbons emitted after combustion in the flare control device.

A typical relief gas header is connected to both a flare gas recovery system and to one or more flares. Normally all vapor flow to the relief gas header is recovered by a flare gas recovery compressor, which increases the pressure of the flare gas allowing it to be routed to a gas treater for removal of contaminants such as sulfur and then to the refinery's fuel gas system. Gas in excess of what can be handled by the flare gas recovery compressor(s), the treater(s), and/or the fuel gas system end users flows to a refinery flare so it can be safely disposed of by combustion. Therefore, in order to reduce the volume of gas flared, three essential infrastructure elements are required: sufficient compressor capacity to increase the pressure of the gas to the point where it can be used in the refinery fuel system, sufficient storage volume to dampen out the variation in volumetric flow rate from the relief gas header, and sufficient capacity in treating systems to condition the gas (primarily by removal of sulfur) for use in the fuel gas system.

Many types of systems are used for compression of flare gas. Options include centrifugal, reciprocating, and rotary compressors, as well as liquid jet ejectors. Each of these options has advantages and disadvantages that lead to it being better suited for use under certain sets of conditions. Centrifugal compressors generally have low maintenance requirements, but are more sensitive to variation in gas properties (e.g., molecular weight) than a reciprocating machine is. Reciprocating compressors, although designed to operate best with a gas that has a specific molecular weight, can operate with a range of compositions so long as inter-stage temperature limits (300 – 350°F is typical) are not exceeded. The rule-of-thumb maximum practical capacity for a single reciprocating compressor is about 4 MMSCFD of gas at the compressor inlet. Rotary screw compressors are less expensive, but generally less reliable

than other options. Liquid ring compressors are less efficient than most reciprocating or centrifugal machines, and cannot achieve as high an outlet pressure, however they have a high tolerance for variation in composition, including some liquid. They are less likely to go into surge than centrifugal or reciprocating compressors. Liquid jet ejectors are very reliable; as they have no moving parts in contact with the gas stream. They can handle a rapidly varying vapor load, but are much less efficient than other types of compressors, so have high power requirements as a result.

Options for storage of flare gas are analogous to those for storage of other process gases. Gases can be stored at low pressure in expandable gas-holders with either liquid (water) or dry (fabric diaphragm) seals. The volumes of these systems expand and contract as gas is added or removed from the container. Very large vessels, containing up to 10,000,000 cubic feet of gas can be constructed by using multiple “lifts”, or stages. Gases can also be stored at higher pressures, and correspondingly lower volumes, in steel bullets or spheres. The optimal pressure vessel configuration depends on system design pressure and total required storage volume.

For any type of gas storage facility, selection of an acceptable site and obtaining the permits necessary for construction both present difficulties. Despite the refinery’s demonstrated commitment and strong track record with respect to safe handling of hazardous materials, there are always concerns about any plan calling for the storage of large volumes of flammable gas containing hydrogen sulfide and other sulfur compounds. Safety concerns are expected to impact site selection as well. Although the objective of the project would be a reduction in flaring, there are expected to be multiple hurdles along the path to a construction/land use permit.

The fact that flare gas is flammable creates safety concerns if large volumes are to be stored. A 60 ft diameter storage sphere filled with flare gas at 140 psig carries with it significant risks if the gas escapes and is ignited. Combustion of flammable gases as they are produced, either in process equipment or in a flare system, is intrinsically safer than storage, as it minimizes the onsite inventory of combustible material. The minimization of on-site storage of combustible gases also addresses Homeland Security concerns.

Flare gas treating is used to condition flare gas for use as fuel in the refinery fuel gas system. Treatment is focused on removal of sulfur compounds, with some systems improving fuel value by removing carbon dioxide as well. A range of technology options exist, most of which are based on absorption of acid gases into a “lean” amine solution (MEA, DEA, MDEA, DGA) with regeneration of the resulting “rich” solution by stripping at lower pressure. In order to recover additional fuel gas it is necessary to have sufficient capacity to match the capacity of gas treating systems to the peak flow rate of the flare gas requiring treatment.

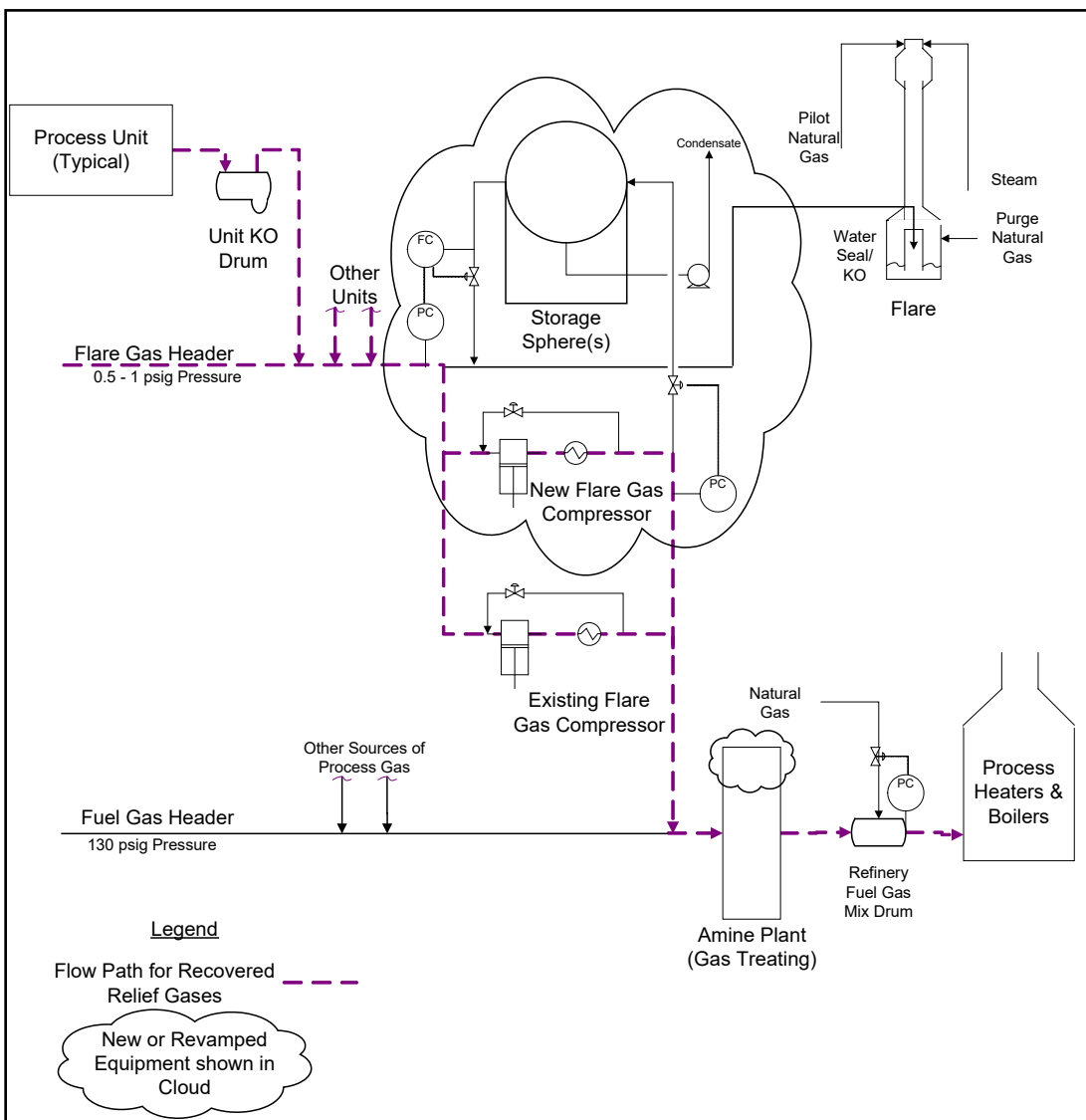
5.2.5 Evaluation of Options for Additional Capacity

In order to assess the potential effect of additional flare gas recovery at the Richmond Refinery, a hypothetical design for an upgraded system was developed. This design considers options separately for each of the North Yard and South Yard Flare Gas Recovery Systems, since they are independent within the Richmond Refinery. The impact that the hypothetical design would be expected to have on hydrocarbon emissions, based on the refinery’s recent flaring history, was then evaluated from an emissions reduction and cost effectiveness point of view.

A simplified diagram of the hypothetical design is shown in Figure 5-2. The diagram in Figure 5-2 highlights differences from the typical Flare Gas Recovery System shown previously in Figure 1-1. Results of this evaluation are provided for two system capacities for the North Yard

Flare Gas Recovery System, and two system capacities for the South Yard Flare Gas Recovery System.

Figure 5-2, Flare Gas Recovery System with Additional Capacity



Basis for Evaluation:

A few specific cases for changes to the refinery's capacity to recover relief gases were evaluated. The cases evaluated correspond to several increments of additional capacity for recovering relief gases, the major equipment installations required to achieve that recovery, and the estimated total installed cost for the additional equipment. Budgetary level (order of magnitude) cost information for each of the cases evaluated is shown in Table 5-3.

Table 5-3 Capital Cost Estimates for Increased Recovery Capacity (Note 8)

<i>Additional Vent Gas Compressor Capacity</i>	<i>Costs of Additional Vent Gas Compressor Capacity</i>	<i>Costs of New Surge Storage (24 hrs at Flow rate)</i>	<i>Costs of Additional Gas Treating Capacity (at indicated Flow rate)</i>	<i>Total for Additional Compressor, Storage and Treating Capacity</i>
1.0 MMSCFD	\$ 3,400,000	\$ 2,500,000	\$ 800,000	\$ 6,700,000
2.0 MMSCFD	\$ 5,000,000	\$ 4,500,000	\$ 1,700,000	\$ 11,200,000
4.0 MMSCFD	\$ 6,700,000	\$ 10,000,000	\$ 3,200,000	\$ 19,900,000

Note 8: All values indicate estimated total installed capital cost. Estimates based on total installed cost data from similar installations where available. Otherwise, vendor quotes, in combination with standard industry cost estimation procedures, have been used to estimate system cost. Monetary value is expressed in dollars for the year 2005.

Each case evaluated is based on the need for installation of three major systems in order to increase recovery of flare gases from current levels:

Additional Vent Gas Compressor Capacity

This cost is based on providing additional compressor capacity to recover vent gas flowing in the relief gas header in excess of current existing compressor capacity. The additional capacity would be used for transfer to storage and/or treatment. Costs provided are for one un-spared reciprocating compressor system to be added to the existing main relief gas header.

New Surge Storage

This cost is based on providing temporary surge storage for a portion of the gases routed to the relief gas header in excess of the volumes currently being recovered, treated, and consumed. The addition of temporary surge storage volume is necessary for any further increase in flare gas recovery capacity, since it allows for flare gas flow (which is highly variable) to be balanced with the demand for fuel gas. The cost used is based on a storage volume equal to the total volume of gas accumulated over one day at the identified flow rate, and is based on recovery in a high pressure sphere system capable of discharging directly back into the refinery fuel gas system. Other lower pressure approaches were considered (low pressure gas holder, medium pressure sphere), but for the sizes analyzed a high pressure sphere was identified as the technically preferred approach based on operational, safety and economic considerations.

Additional Gas Treating Capacity

The cost of additional amine-based treating capacity to process recovered gases for sulfur removal so that they can be burned by existing fuel gas consuming units without exceeding environmental or equipment operational limits. Installed cost data for new treatment systems was scaled to estimate the cost of adding additional treatment capacity to the refinery's existing treatment systems.

North Yard Flare Gas Recovery (FGR) System Evaluation:

The North Yard flares are tied into a single FGR system which is evaluated in this section.

- Sampling data from reportable flaring events has been reviewed, identifying that the hydrocarbon content in the flared gases has ranged from 20% to 90% (as propane), with an average value of 62%. This average hydrocarbon content value corresponds to 0.07 lbs of hydrocarbon in each standard cubic foot (SCF) of flared gas. Applying 98% efficiency for the flare combustion device, this corresponds to 0.0014 lbs of hydrocarbon emissions per SCF of vent gas flow sent to the flare.
- The daily average flaring data has been reviewed for the 2005 calendar year leading to the conclusion that, on an annual basis, the addition of 2 MMSCFD of additional (un-spared) compressor system (including storage and treating) capacity would capture approximately 52 MMSCFD of gases currently flared. This evaluation has been performed by totalizing the volume of gas currently routed to the flare that could be captured by a system with a flow capacity of 2 MMSCFD. Daily data for flow to the North Yard Flares was used for the evaluation. Flow in excess of the 2 MMSCFD rated compressor capacity cannot be recovered by this system.
- A similar evaluation has been performed to determine the impact of adding 4 MMSCFD additional flare gas compressor system capacity. This would result in the capture of an additional 62 MMSCFD of flared gases on an annual basis.
- Applying the average gas composition and the lb hydrocarbons emitted per SCF of flared gas factor to the identified reduction in flared gas volumes, maximum possible reduction in hydrocarbon emissions if all 2005 flared emissions were captured was estimated at 73,161 lb/year for 2 MMSCFD additional flare gas compressor capacity and 86,859 lb/year for 4 MMSCFD additional flare gas compressor capacity.
- Using the emission estimates above, with cost estimates from the table above (annualized per the BAAD BACT workbook), annual operating cost estimates, and AP42 emission factors and other engineering estimates, the cost effectiveness for 2 MMSCFD additional flare gas compressor capacity was estimated at:

- \$86,000 per ton of non-methane hydrocarbon (NMHC) reduced, or
- \$39,000 per ton of SO₂ reduced, or
- \$235,000 per ton of CO reduced, or
- \$1.3 MM per ton of NO_x reduced, or
- \$9.2 MM per ton of soot reduced.

Similarly, the cost effectiveness for 4 MMSCFD additional flare gas compressor capacity was estimated at:

- \$119,000 per ton NMHC reduced, or
- \$53,000 per ton of SO₂ reduced, or
- \$325,000 per ton of CO reduced, or
- \$1.8 MM per ton of NO_x reduced, or
- \$12.7 MM per ton of soot reduced.

These estimates significantly exceed the \$20,000/ton NMHC emission reduction BAAD threshold for cost effectiveness referenced in the District's staff report for 1997 amendments to BAAD Rule 8-28.

- An additional factor that would severely limit the reduction in emissions such a recovery system would achieve in practice is the capability of the fuel gas consumers to accept these gases at the time at which they are generated (from both a volume and quality perspective).

South Yard Flare Gas Recovery (FGR) System Evaluation:

The South Yard flare (LSFO flare) is tied into a single FGR system which is evaluated in this section.

- Sampling data from reportable flaring events has been reviewed, identifying that the hydrocarbon content in the flared gases has ranged from 9% to 100% (as propane), with an average value of 16%. This average hydrocarbon content value corresponds to 0.07 lbs of hydrocarbon in each SCF of flared gas. Applying 98% efficiency for the flare combustion device, this corresponds to 0.02 lbs of hydrocarbon emissions per SCF of gas flow to the flare.
- The daily average flaring data has been reviewed for the 2005 calendar year leading to the conclusion that, on an annual basis, the addition of 1 MMSCFD of additional (un-spared) compressor system (including storage and treating) capacity would capture approximately 6.4 MMSCF of gases currently flared. This evaluation has been performed by totalizing the volume of gas currently routed to the flare that could be captured by a system with a flow capacity of 1 MMSCFD. Daily data for flow to the South Yard Flare (LSFO Flare) was used for the evaluation. Flow in excess of the 1 MMSCFD rated compressor capacity cannot be recovered by this system.
- A similar evaluation has been performed to determine the impact of adding 2 MMSCFD additional flare gas compressor system capacity. This would result in the capture of an additional 8.1 MMSCF of flared gases on an annual basis.
- Applying the average gas composition and the lb hydrocarbons emitted per SCF of flared gas factor to the identified reduction in flared gas volumes, maximum possible reduction in hydrocarbon emissions if all 2005 flared emissions were captured was estimated at 2,297 lb/year.
- Using the emission estimates above, with cost estimates from the table above (annualized per the BAAD BACT workbook), and annual operating cost estimates, the cost effectiveness was estimated at \$1,687,000/ton NMHC reduced for 1 MMSCFD additional flare gas compressor capacity and \$2,038,000/ton NMHC reduced for 2 MMSCFD additional flare gas compressor capacity. These estimates significantly exceed the \$20,000/ton emission reduction BAAD threshold for cost effectiveness referenced in the District's staff report for 1997 amendments to BAAD Rule 8-28.
- An additional factor that would severely limit the reduction in emissions such a recovery system would achieve in practice is the capability of the fuel gas consumption units to accept these gases at the time at which they are generated (from both a volume and quality perspective).

Conclusions:

Based on this review and the high efficiency of the present system the Richmond Refinery has concluded that further expansion of systems for the recovery, treatment and use of flared gases is neither a cost effective nor feasible approach to reducing these emissions. The Richmond Refinery and general industry practices have identified that the major source of flared gases on a volume basis can be attributed to large flow rate flaring events, especially those of extended

duration such as may occur during emergency events or prolonged shutdowns where systems within the refinery are out of fuel gas (and / or hydrogen) balance.

The Richmond Refinery has allocated significant resources to the development of procedures to plan for, manage, and minimize large flow and duration flaring events. Further resources have also been allocated effectively to ongoing preventive maintenance programs, and even to adjust refinery operations on a severity and throughput basis. These approaches have been identified to be more effective than providing additional flare gas recovery system capacity.

5.2.6 Preventing Production of Low-Quality Fuel Gas

Measures to help prevent production of low-quality fuel gas, (e.g., sour gas, low Btu gas, high nitrogen content) are further investigated in this section. The discussion is integrated with the discussion of turnaround and maintenance events as gas quantity (insufficient demand) and gas quality (unscrubbed during upset/malfunction and nitrogen/steam during turnaround) are the primary drivers for flaring during these events. It is for this reason that the measures used to minimize production of low quality fuel gas are closely related to those that can be applied to reduce flaring during maintenance and turnaround events.

Preventing production of sour fuel gas is accomplished by making sure that recovered flare gas is routed to the fuel gas system via a gas treating system. It is preventing the production of sour fuel gas that drives the need to match the capacity of treating systems to accept flare gas to flare gas recovery capacity.

High fuel gas nitrogen levels are primarily caused by the nitrogen used to purge hydrocarbons from equipment in preparation for equipment opening. High nitrogen fuel gas content is controlled by limiting the rate at which nitrogen is introduced to equipment and ultimately the flare gas system during nitrogen purging operations. There can be a trade-off between nitrogen flow rate and the effectiveness with which the nitrogen mixes within the contents of the vessel from which hydrocarbons are being removed. These must be balanced on a case-by-case basis to determine the purge rate that represents the best compromise among competing process needs.

5.2.7 Minimizing Sulfur Emissions from Flaring

Historical changes and planned improvements to reduce flaring that were included in Tables 3-1 and 4-1 have had an overall effect of reducing the amounts of hydrocarbons sent to flares, and a corresponding reduction in the amount of sulfur compounds released. The cycle of refinery turnarounds can cause the overall emissions from flares to vary over time, which will likewise affect emissions of sulfur compounds. The flare planning process as described in Section 5.1.6 is a primary means to reduce emissions of sulfur compounds by minimizing flaring activity.

Causal analyses performed for releases of sulfur compounds have generated some of the historical changes and planned improvements to reduce flaring included in Tables 3-1 and 4-1.

The setup of North Yard flares described in Section 2.1 is another means by which releases of sulfur compounds are minimized.

Additionally, all flare vent gases that can be recovered by the FGR compressors are sent to the Refinery's H₂S plants for removal of H₂S so that the gas can be used as refinery fuel gas. All flare gas generated by planned operations in the North Yard and South Yard is recovered by the FGR compressors except when high nitrogen, steam or hydrogen content would cause

overheating of the compressors. FGR compressors have been upgraded to increase their capability to handle these conditions.

5.3 Recurrent Failure

This section provides information on prevention measures for flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Pursuant to Regulation 12, Rule 12, Section 401.4.3, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause as identified by cause investigations conducted pursuant to the requirements of Regulation 12, Rule 12, Section 406 (i.e., after July 20, 2005).

The Richmond Refinery has in place a preventative maintenance program that is consistent with recognized industry standards and recommended practices (e.g., American Petroleum Institute 520). This program includes procedures and policies to maintain the reliability of equipment so that equipment failures and other types of process upsets are minimized or eliminated. When equipment or systems do fail and impact operations (or cause significant flaring), investigations are conducted to identify the cause of the failure and implement suitable corrective actions. The flowchart shown previously in Figure 2, which illustrated the investigative process for planned and unplanned maintenance events, is also followed when equipment fails or processes experience upsets.

Between July 1, 2024 and June 30, 2025, there were no flaring events caused by recurrent failures.

5.4 Other Potential Flaring Events

The flowchart shown in Figure 5-1 covers the range of potential flaring events that the refinery might experience.

Appendix A – Simplified Flow Diagrams Chevron Richmond Refinery Flare Systems

This section included in Trade Secret Transmittal,
Submitted under separate cover.

Trade Secret Information

Drawings in this Appendix are trade secrets of Chevron Products Company as defined in California Public Records Act, Section 6254.7 of the Government Code. The information shown in these drawings reveals information about the refinery's operation that could harm Chevron's competitive market position. This response is protected from public disclosure under California law, including Government Code Section § 6254.7, and the District's procedures in Section 11 of the District's Administrative Code. Because of the sensitive and competitive nature of the information, Chevron Products Company requests that the BAAD afford the information Confidential Business Information treatment indefinitely. These drawings are not subject to public disclosure as a public record without the express written consent of Chevron Products Company.

Appendix B – Flare P&IDs

Chevron Richmond Refinery Flares

This section included in Trade Secret Transmittal,
Submitted under separate cover.

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Appendix C – Flare Elevation Drawings

Chevron Richmond Refinery Flares

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Appendix D – Technical Summaries of Compressors and Fuel Gas System Chevron Richmond Refinery Flares

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Submitted under separate cover.

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