FACILITY PERMIT TO OPERATE
PHILLIPS 66 COMPANY/LOS ANGELES REFINERY

SECTION I: PLANS AND SCHEDULE

This section lists all plans approved by AQMD for the purposes of meeting the requirements of applicable AQMD rules specified below. The operator shall comply with all conditions specified in the approval of these plans, with the following exceptions:

a. The operator does not have to comply with NOx or SOx emission limits from rules identified in Table 1 or Table 2 of Rule 2001(j) which become effective after December 31, 1993.

b. The operator does not have to comply with NOx or SOx emission limits from rules identified in Table 1 or Table 2 of Rule 2001(j) after the facility has received final certification of all monitoring and reporting requirements specified in Section F and Section G.

Documents pertaining to the plan applications listed below are available for public review at AQMD Headquarters. Any changes to plan applications will require permit modification in accordance with Title V permit revision procedures.

List of approved plans:

Application	Rule
539607	2002
539609	1123
539610	1176
539611	63SubpartUUU
539616	1173
539618	1118
555297	1118

NOTE: This section does not list compliance schedules pursuant to the requirements of Regulation XXX – Title V Permits; Rule 3004(a)(10)(C). For equipment subject to a variance, order for abatement, or alternative operating condition granted pursuant to Rule 518.2, equipment specific conditions are added to the equipment in Section D or H of the permit.

Los Angeles Refinery

Flare Minimization Plan

SCAQMD Rule 1118(e)

Original submission:
March 30, 2013

Updated February 20, 2014

Section 1.0 Summary of 2012 Flaring Activity and Objectives of the Flare Minimization Plan

The Phillips 66 Los Angeles Refinery (LAR) consists of two manufacturing locations, the Carson and Wilmington Plants which are approximately 5 miles apart and are connected by pipelines. The Carson Plant separates crude oil into its primary fractions in the refining process and performs some sulfur removal and coke production; the Wilmington Plant performs additional sulfur removal and produces finished fuel products from the primary fractions. Collectively, both locations function as a single petroleum refinery turning crude oil into finished products.

LAR has significantly reduced flaring since the passage of South Coast Air Quality Management District (SCAQMD) Amended Rule 1118 in 2005. The Carson Plant installed a new vapor recovery system, and the Wilmington Plant completed a major project to both interconnect and enhance the existing vapor recovery system. At both locations, recovered flare gas is routed to amine treatment systems to remove H_2S, and is then routed to a refinery fuel gas system to be used as fuel for heaters and boilers within the refinery.

Oxides of Sulfur (SOx) are the primary pollutants associated with flaring sour gases from petroleum refineries. LAR reduced SOx emissions from 68.4 tons to 31.3 tons, a reduction of 54%, from 2007 to 2012. LAR was also successful in significantly reducing the number of flare events and the total volume of gases that were routed to the flare during the same period.

Rule 1118 specified an aggressive performance target for the South Coast refineries to reduce SOx associated with flaring by 66.7% from 2007 to 2012. The performance target was based on a particular refinery's crude throughput rates, and resulted in a performance target of 25.4 tons for LAR. Because both locations function as a single petroleum refinery, the emissions from both locations are combined and compared to the LAR performance target of 25.4 tons.

Despite the vapor recovery projects, LAR was not able to meet the performance target in 2012 and was therefore required to submit a mitigation fee and a Flare Minimization Plan as required by Rule 1118(d)(3) and Rule 1118(e) respectively.

In 2012, LAR emitted 31.2 tons of SOx compared to the performance target of 25.4 tons. The mitigation fee associated with exceeding the performance target by 5.8 tons is $580,000, calculated in accordance with the schedule of Rule 1118(d)(3)(B)(iii), and was submitted to the AQMD on March 30, 2012.

The Flare Minimization Plan (FMP) constitutes a plan pursuant to Rule 221 and requires review and approval by the SCAQMD. The purpose of the FMP is to address the issues that caused the performance target exceedance and put into place prevention measures, corrective actions, policies and procedures that can be used to minimize or eliminate, to the extent feasible and safe, similar events in the future.

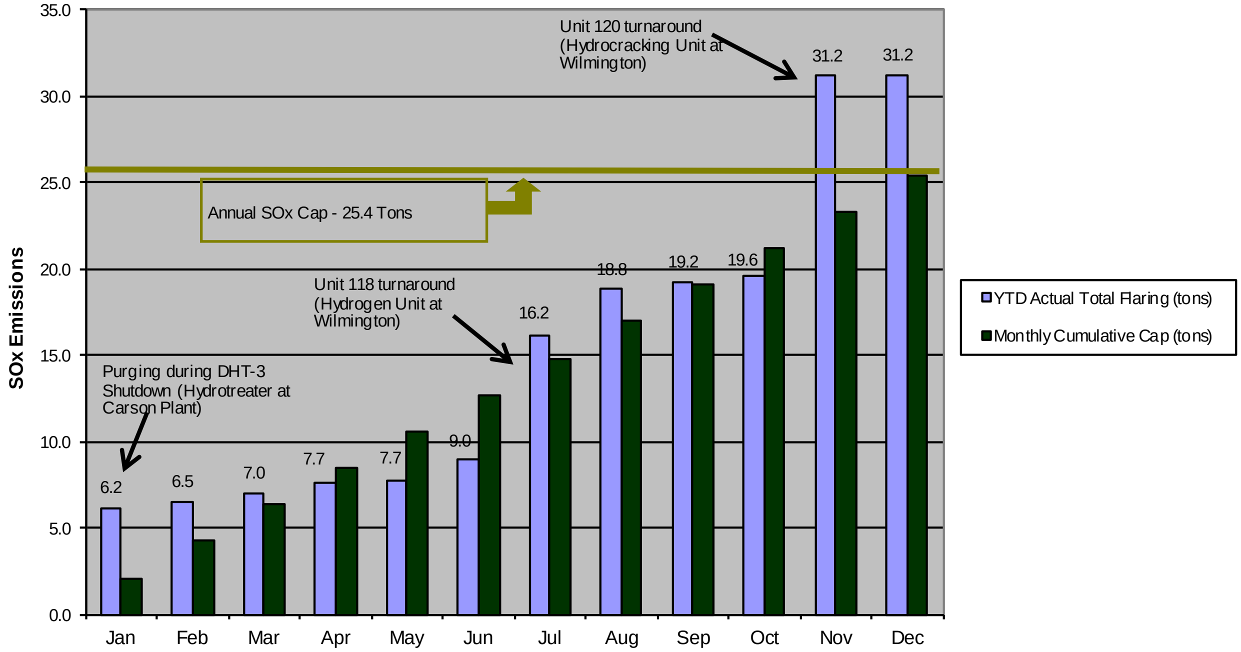
As shown in Figure 1, an analysis of the SOx emissions during 2012 shows that the bulk of the emissions are associated with three major start-up/shut-down activities. The three turnarounds were the one of the two hydrotreating units at the Carson Plant (Distillate Hydrotreater, DHT-3) in January (contributing 4.6 tons of SOx emissions, or 18% of the performance target), the hydrogen plant at Wilmington (Unit 118) in July (contributing 6.3 tons, or 25% of the performance target), and the hydrocracker (Unit 120) start-up at Wilmington in November (contributing 10.5 tons, or 40% of the performance target).

Specific work practices have been identified by LAR to reduce future turnaround emissions from Unit 118 and both of the Carson hydrotreaters (DHT-3, and the High Pressure Distillate Treater, HDT) and are described in this plan.

Hydrocracker turnarounds occur infrequently, typically on 5-6 year cycles. Specific flare minimization work practices for the next Unit 120 turnaround are still in the developmental phase. As described in Section 4.2, LAR has instituted flare minimization as part of all turnaround planning. The Environmental Department meets with Operations to develop work practices and shutdown strategies to not only reduce the concentration of sour gases but also to reduce the total volume of vent gases flared and duration of flaring. The procedures for a Unit 120 turnaround will be formalized and documented prior to the next turnaround.

Additionally, as described in Section 4, a major capital improvement was made to the flare gas recovery system at the South end of the Wilmington plant. This is expected to reduce emissions from all flaring activities, including a future turnaround of the hydrocracking unit.

Figure 1
LAR SOx Emissions from 2012 Flaring Activities



Note: The Wilmington hydrogen plant does not contain significant volumes of sour (sulfur containing) gases. See explanation in Section 2 of the refinery integrated vapor recovery system that is shared by all units and how the hydrogen unit contributed to SOx emissions.

Section 2.0 Description and Technical Specifications for the Flare System and Associated Equipment

Wilmington Plant
The Phillips 66 Wilmington Plant has three general service flares and one clean service flare. The general service flares are: the North (Device #C-706); Unicracker (UK) (Device #C-748); and South (Device #C-723). The liquefied petroleum gas (LPG) Flare (Device #C-736) is a clean service flare as defined under SCAQMD Rule 1118 in that it only receives "clean" gases that do not contain significant amounts of sulfur. The North, UK, and South Flares are interconnected by a common header and hydrocarbon recovery system (HRS).

Gases are collected in the 36' centralized header of the HRS and are routed to Knockout Drums F-7 and F-701 for the northern refinery units and to Knockout Drum F-155 for the southern units. Each Knockout Drum has an associated seal drum in which recovered liquids are sent to the plant recovered oil system. Vapors are captured by three vapor recovery compressors.

The North and UK flares are 36" diameter John Zink Model EEF-QS steam assisted flares. The South flare is a 36" diameter John Zink steam assist with Kaldair flame control. The maximum design capacity of the North, UK, and South flares are 1,120,000 Lb/hr, 655,000 Lb/hr, and 1,220,000 Lb/hr respectively.

In the event of excess gases or over-pressure in a processing unit, hydrocarbon and inert gases, occasionally along with entrained liquids, will enter the HRS at the affected process unit boundary. The gases/liquid flow enters a knockout drum common to multiple units, where the liquid is separated by gravity from the gases and the liquid is routed to an oil recovery system. The hydrocarbon and inert gases continue toward a seal drum. The suction line to the vapor recovery compressor(s) is located upstream of the seal drum. This allows the gases to be taken by the compressor, compressed, and sent to a process unit for sulfur removal and gas recovery. The water seal in the seal drum acts as a stopping mechanism to prevent gases from flowing directly to the flare stack under normal low pressure conditions. If the pressure created by the relieving gases in the line to the seal drum is greater than the back pressure created by the water, then the gases are relieved to the flare. A molecular seal provides a barrier to prevent air from entering the flare stack and creating an explosive environment within the stack. This also reduces the amount of purge gas required for the purge system. Steam is injected at the flare tip to promote proper combustion, and can be adjusted as necessary. The purge gas (natural gas) is a continuous purge to provide a positive flow through the flare stack. The purge gas rate is typically on flow control. The purge gas rate is specified by the flare tip manufacturer.

In the staged flare system, routing of flare system gases that exceed the available vapor recovery capacity will be controlled by the relative heights of the liquid seals in each drum. Heavy relief flows from any unit(s) will be directed first to the in-service flare with the greatest smokeless capacity, normally the North Flare, or the in-service flare with the greatest smokeless control at low flare volumes, normally the UK Flare. If a heavy flow event occurs due to a process upset or breakdown, excess flow will successively ‘spill over” to the second and third flare, as needed.

The LPG Clean Service Flare is completely isolated from the common refinery flare systems. There is no vapor recovery on the LPG flare system.

Carson Plant

The Phillips 66 Carson Plant has two general service flares: the East Flare (Device No. C-465) and the West Flare (Device No. C-469).

Excess gases from the East Units are collected into a 20” main header and routed to Knockout Drum V-2254 and the West Units are routed to Knockout Drum V-2540. Entrained liquids are removed from this drum sent to the plant recovered oil system. The gases are captured by vapor recovery compressors.

The East Flare Stack SA-4 is a derrick design. The flare tip is 30” in diameter and has steam injection and air induction tubes to promote combustion. The flare stack was originally built in 1969 and modified with a new flare assembly design in 1986. Maximum flare tip capacity with a stable flame is approximately 600,000 Lb/hr. Maximum smokeless capacity is 100,000 Lb/hr.

The West Flare Stack SA-6 was originally built in 1982 and modified with a John Zink molecular seal in 1994. The flare tip is 24” in diameter and has steam injection around the outer rim and in the center. Maximum designed tip capacity is 250,000 Lb/hr. Maximum smokeless capacity is 45,000 Lb/hr.

Compressed gases from the vapor recovery compressors are treated to remove sulfur compounds. The treated and recovered gas is then used in the refinery fuel gas system. As with the Wilmington system, the water seal in the seal drums at the Carson plant creates backpressure to prevent gases from flowing directly to the flare stack. If pressure in the HRS is greater than the backpressure created by the water in the seal drum, then the gases are relieved to the flare. The molecular seal on the flare provides a barrier to prevent air from entering the flare stack. This also reduces the amount of purge gas required for the purge system. Steam is injected to promote proper combustion, and the rate can be adjusted as necessary. The purge gas (natural gas) is a continuous purge to provide a positive flow through the flare stack. The purge gas rate is on flow control.

Vapor Recovery Systems

Wilmington Plant

The Phillips 66 Wilmington Plant has an integrated Vapor Recovery System serving the North, UK, and South general service flares. The North, UK, and South Flares and associated piping are integrated into a single system by sealing each flare with a water seal drum in a staged design, and are served by three vapor recovery compressors: GB-151 and GB-152 in the South area, and GB-951 in the North area. With interconnection, any compressor can recover vapor from all operating units regardless of location, maximizing the flexibility and capacity of the vapor recovery system.

A disadvantage of a centralized HRS is that both units having sour gases and units that do not have sour gases vent to the same header. If there is venting from a unit that does not contain sour gases, such as a hydrogen plant, the event sweeps the sour gases from the non-upset units to the flare, resulting in SOx emissions from a unit without appreciable sulfur content. Procedures are described in this plan the will be used to minimize this effect in planned turnaround activities of non-sour gas units.

All three vapor recovery compressors are reciprocating type. Cylinder loading for GB-951 and GB-152 is controlled based on suction pressure. Rising suction pressure causes cylinders to be loaded in steps until the compressor is fully loaded. GB-151 is proportionally loaded using a recycle line to prevent overheating the compressor under low loading conditions. As described in Section 4, a major capital improvement was made to this compressor in December 2012 to increase efficiency and reliability of the machine.

The suction pressure at each compressor varies depending upon seal liquid height, flare system gas flow, and resealing time following a flare event. When the flare system flow is low, the compressor is able to keep the HRS pressure from pushing through the flare seal at partial cylinder loading. At higher flare system flow rates, the pressure increases, causing the compressor controller to load more cylinders. Flow in excess of the compressor capacity at full load can cause the flare liquid seal to be displaced if the pressure in the HRS becomes high enough. The controllers are set to load the compressors to 100% before the flare liquid seal is broken. The capacity of the vapor recovery system at the Wilmington plant is 2865 scfm. Under normal operating conditions, the amount of vapor vented to the HRS is approximately 1448 scfm.

Carson Plant

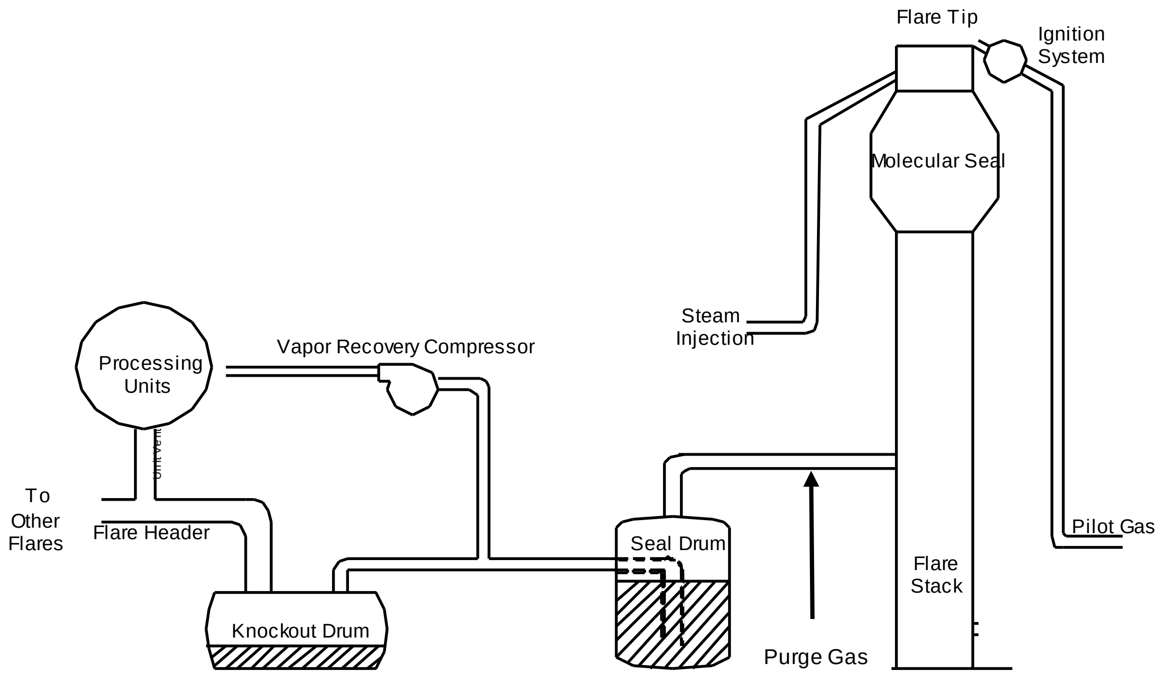
Two Liquid ring-sealed Garo compressors (HP-3016 and HP-3017) are utilized to compress recovered flare gases from the Carson East and West flares. Two seal drums hold back pressure so that the vapor recovery system can capture all of the non-emergency venting.

The compressors are fully instrumented with distributed control system (DCS) functionality to record compressor loading. Flow meters are also in place to monitor and record flare gas vapor recovery amounts.

When the flare system flow is low, the compressors are able to keep the HRS pressure from breaking the flare seal at partial loading. At higher flare system flow rates, the pressure increases, causing the compressor controller to increase compressor loading. Flow in excess of the two compressors capacity at full load can cause the flare liquid seal to be displaced if the pressure in the header becomes high enough. The controllers are set to load the compressors to 100% before the flare liquid seal is broken. The capacity of the vapor recovery system at the Carson plant is 1800 scfm. Under normal operating conditions, the amount of vapor vented to the HRS is 540 scfm.

Figure 2 shows a representation of a typical flare and vapor recovery system at LAR.

Figure 2 - Schematic of Flare System Configuration



Flare Gas Treatment

Wilmington Plant

Once the flare gas is recovered, it is sent to the Unit 110 Fuel Gas Absorption System to be treated. There, it is contacted with Monoethanolamine (MEA) in order to remove sulfur, and then placed into the common refinery fuel gas system. As the overall treatment capacity of the Fuel Gas Absorption System is approximately 13,900 scfm compared to the vapor recovery system capacity of 2865 scfm, there is more than adequate treatment capacity for the recovered flare gases.

Carson Plant

The treatment system at the Carson Plant is similar to the Wilmington Plant, except that Diethanolamine (DEA) is used to remove sulfur. The treatment occurs in the Vacuum Flasher with a capacity of approximately 11,000 scfm compared to the vapor recovery capacity of 1800 scfm.

Section 3.0 Detailed Process Flow Diagrams of Upstream Equipment and Process Units Venting to the Flare System

Flow diagrams of the interconnected flare system at the Wilmington and Carson Plants as well as the upstream units and equipment vented to the header system are provided in Attachment A. These drawings contain confidential business information as defined by the California Public Records Act, Government Code § 6254.7, and the Freedom of Information Act, 40 CFR Part 2, §2.105, and are therefore submitted in a sealed envelope to be opened and reviewed by SCAQMD staff only. Each drawing is stamped with a bold red "confidential" stamp, and is not to be released to the public without prior written permission from the Phillips 66 Company. A public review version of this FMP has also been submitted without the drawings in Attachment A.

The following drawings are provided in Attachment A:

Drawing Number	Title/Description
Wilmington Plant	
W-338-X-001	Hydrocarbon Relief and Recovery System
W-337-X-002	South Flare and Vapor Recovery System
W-424-X-014	Sulfur Absorption and Refinery Gas Augmentation System
W-415-X-003 Sheet 1	FCC Unit – FCC Section
W-415-X-003 Sheet 2	FCC Unit – CLEF Section
W-433-X-002	Sulfur Plant – Sour Water Stripping Facilities
W-449-X-003	Hydrogen Plant – Reforming and Steam Generation
W-424-X-007	Alkylation – Fractionation Section
W-450-X-003	Unicracker – Reaction Section
W-450-X-004	Unicraker – Fractionation Section
W-442-X-001	Reforming
W-438-X-002	Turbine Fuel Unifining – Distillation Section
W-412-X-002	Butane Processing
W-412-X-001	Penex Plus
Carson Plant	
C-410-X-1000	Crude Unit
C-370-X-1000	C3/C4 Gas Plant
C-414-X-001	Hydrogen Plant
C-418-X-1000	DEA Plant
C-418-X-1001	Sulfur Plant
C-418-X-1002	Tail Gas Treating
C-412-X-001	Hydrotreating
C-419-X-001	Hydrotreating
C-422-X-001	Vacuum Distillation
C-420-X-1005	Delayed Coking

Following is a functional description summary of the units venting to the HRS and characteristics of the waste vent gases

Unit	Description	Vent gases to hydrocarbon recovery system
U-152	Fluidized Catalytic Cracking – converts high boiling point, high molecular weight hydrocarbon to gasoline fractions and olefin gases	Wet Sour gases containing hydrogen sulfide (methane, ethane, propane, butane, pentane and olefin gases)
U-138	Sulfur Plant – Converts sour gases to sulfur	H_2S– emergency venting only
U-118	Hydrogen Plant – steam reforming of methane	Hydrogen, methane, CO, and CO_2 – startup, shutdown, and emergency flaring only
U-110	Alkylation – converts isobutane, propane/propene, butane/butene to high octane blend stock	Isobutane, propane, butane, light olefin gases
U-120	Unicraking/Hydrocracking – produces high purity jet and diesel range fuels with low sulfur content	Sour gases, hydrogen, propane, butane, pentane, hexane, paraffin gases
U-80/100	Reforming – converts petroleum naphtha to high octane containing gasoline and isoparaffins	Methane, ethane, propane, butane, caustic gases, hydrogen chloride
Unit 89/90	Hydrotreats diesel and jet range fuels to produce low sulfur containing distillates	Hydrogen, sour naphtha, pentane, hexane, olefin gases
Unit 60	Butane Processing –isomerizes normal butane to isobutane	Propane, butane, hydrogen chloride, caustic gases
Unit 60	Penex – removes benzene from light naphtha and light reformate. Isomerizes pentanes and hexanes into high octane blending stocks	Hexane, pentane, hydrogen chloride, caustic gases
Crude Unit	Salt removal and primary separation of crude oils	Methane, ethane, propane, butane, pentane sour naptha, olefin gases, olefin and aromatic liquids
C3/C4 Unit	Treats and separates light end gases	Propane, butane, disulfide
Hydrogen Plant	Steam reforming of methane	Hydrogen, methane, CO, CO2, solexol
DEA Plant	Removes sulfur compounds from DEA for recirculation	H_2S – emergency venting only
Sulfur Plant	Converts sour gases to sulfur	H_2S – emergency venting only
Tail gas treatment	Removes remaining sulfur from sulfur plant tail gas	H_2S – emergency venting only
Hydrotreating	Produces low sulfur gas oils	Hydrogen, propane, butane, pentane, paraffin gases, sour gases, olefins
Flasher	Vacuum Distillation	Heavy gas oils
Coker	Converts pitch and heavy hydrocarbons to Coke	Heavy gas oils, coker gases, sour gases

Section 4.0 Equipment Improvements to Minimize Flaring Emissions, and Refinery Policies and Procedures to be implemented to Comply with the Phillips 66 Performance Target.

4.1 Upgrades to South Vapor Recovery System (Wilmington Plant)

Flare gas recovery compressor GB-151 was previously powered by a natural gas internal combustion engine. During October 2012, the GB151 (C686) compressor natural gas driven engine was replaced with an electric motor with belt drive to improve reliability of the compressor and eliminate engine emissions. The following equipment was installed:

1. 350Hp Motor for GB151 (GB151M)
2. New GB151 Compressor components - sprockets, flywheel, outboard pedestal bearing, and frame and gear conversion materials
3. New control panel and associated instruments

The decommissioned compressor to the West side of GB-151 was demolished to provide plot space for the new motor, electrical upgrades, and the new control equipment. An API 547 motor with ancillaries was installed. The motor was mounted aside and to the west of GB-151 and connected via belt drive. Due to the belt drive side loads, the motor has heavy duty roller bearings and automatic grease lubricators and a pedestal bearing was added to the crank shaft of the compressor.

Noise aspects were reviewed in the design and mitigated as necessary. A power feeder and motor starter with diagnostics were installed. Critical motor and compressor parameters were engineered to a shutdown system to protect the equipment. The facility permit was modified to indicate the removal of the natural gas driven engine as an emission source.

Replacement of the internal combustion engine has improved reliability of the flare gas recovery compressor. NOx, CO, and VOC emissions from the engine were eliminated as well as decreasing the potential for flaring due to the former engine's limited ability to handle variable HRS load and gas composition variations.

Sulfur Dioxide emission decreases resulting from the project can only be estimated due to the variable nature of HRS flows. During August 2012, approximately 2 tons of SOx emissions associated with non-start-up/shut-down flaring occurred that most likely would have not been emitted if the compressor had been powered by the more reliable electric motor. The compressor upgrade will also reduce flaring during start-up and shut-down activities when HRS gas recovery load can be at its peak. The improved compressor performance could potentially reduce up to 4.5 tons of emissions from start-up or shut-downs of similar size and duration as during the 2012 operations.

Project Schedule and Cost

The project was completed in December 2012 with an approximate parts and installation cost of $1,970,000. The project is expected to reduce SOx emissions by 6.5 tons annually.

Figure 3 – Completed Motor and Compressor looking south

Figure 4 – Completed Compressor, Motor, and Control Panel looking west

4.2 Work Practices to Reduce Flaring During Planned Turnarounds for Wilmington Unit 118 Hydrogen Plant and Carson HDT and DHT-3 Hydrotreating Units

During unit startups and shutdowns, above normal volumes of vent gases are sent to the vapor recovery system including inert gas purges, steam-outs, and natural gas. As seen in Figure 1, three of these activities contributed the largest portion of flare emissions from LAR during 2012.

LAR has begun a comprehensive review of work practices prior to a planned turnaround. The review is conducted prior to the shut-down jointly by the Operations and Environmental Departments. The objective is to determine the steps that can reduce the duration, concentration of sour gases, and the total volume of flaring during the shutdown process. As with all sequenced shut-down and start-up operations, a single piece of equipment in the process may have influence over multiple pieces of interconnected equipment within the same process. Therefore, an identified minimization practice may not always yield the same results. A procedure could be used identically in two successive years of turnarounds, with differing results in flaring volumes and emissions. For example, in a controlled reduction of charge gas, a compressor could trip off line from low suction pressure and cause pressure swings in downstream columns that are vented to the HRS, but the same controlled charge gas reduction the following year may not cause significant pressure swings and less vent gas would go from the columns to the flares.

Given the expectation that results of work practices may vary, LAR is committed to minimizing flaring and has initiated a concerted effort to develop a compendium of "Turnaround Flaring Mitigation Practices". These are best practices based on operator experience and engineering analysis of specific vessel depressuring methodologies that can be used to reduce flaring in turnarounds, when planned and controlled depressurization is possible. The goal will not only be to reduce the concentration and volume of sour gases flared, but to reduce the overall duration of flaring, and to maximize vent gas recovery. The Turnaround Flaring Mitigation Practices will be documented. Discussions and training with the shutdown crew will occur prior to the turnaround. An example of two expanded procedures established by this process is given below.

The two practices given here were developed based on the 2012 Unit 118 Hydrogen Plant and the 2012 DHT-3 turnarounds. The practices were implemented in 2013 for the Unit 118 turnaround, and a separate hydrotreating unit turnaround at Carson (HDT). Emissions from both of these activities were reduced by improved practices. In 2013, the emissions from both turn around activities totaled approximately 2.8 tons of Sox, compared with the 2012 total of 10.9 tons.

In 2013, with the capital investment in GB-152 and the minimization work practices implemented, LAR was able to achieve the AQMD established SOx performance target for the year. The flare minimization strategy development described in this plan is aligned with the Phillip 66 corporate commitment to safety, operating excellence, and environmental accountability. Phillips 66 is committed to the safety of everyone who works in our facilities, lives in the communities where we operate or uses our products, and in conducting our business with care for the environment.

Flare Minimization Guideline: Shut-down of Unit 118

Describe Change:

- Controlled shutdown of the Unit 118 for a Turnaround.

Consequence of Change:

- Flaring may occur during the U118 shutdown due to the unit de-pressuring hydrogen and the necessity to limit the amount of hydrogen and carbon dioxide to fuel gas.

The steps below are followed prior to shutting Unit 118. These measures will minimize the impact to the fuel system composition and minimize flaring:

Bulk Department:

1) The Bulk Centralized Control Room (CCR) Board operator works with the refinery units to increase steam availability for the flares, in case of venting hydrogen to the flare system is necessary.
2) Switches the Cogen to Speed/Load Control and 100% Make Gas.
3) Places the Cogen Duct Burners in service to increase steam production.
4) Increase purchased natural (IFS) gas going to mix drum and increases load on available boilers to meet refinery steam load.
5) In the event that flaring occurs during the hydrogen depressurization, the Bulk CCR Operator balances and controls flaring between the North and UK flare, and minimizes flaring at South flare to conserve steam.
6) If flaring results in high flame height, visible smoke, or excessive noise, the Bulk Department coordinates with the Hydro Department to reduce the rate of venting from U-118 to the flare.

Hydro Department:

NEW practice from 2012 shutdown to Reduce SOx emissions

1) *Performs a nitrogen purge of the flare line from hydrogen plant to the fuel gas vapor recovery compressors. The purging is done by establishing a controlled flow of nitrogen immediately preceding the shutdown of the PSA units. By purging the HRS, the sour gas present in the header will be sent to fuel gas recovery and treated before it is used as refinery gas. The total flow rate of nitrogen should be low enough to avoid overwhelming the vapor recovery compressors (which could send the sour gas to the flare). It should also be low enough to avoid reducing the heat capacity of the refinery fuel gas. The nitrogen purge should be high enough to eliminate any sour gas in the line within a reasonable period of time. Once the nitrogen purge step is finalized, the PSA can be shut down and excess PSA gas will go to the flare. However, with lower amounts of sour gas in the HRS, the gas going to the flare will only have minimal amounts of H2S and thus the SOX emissions will be reduced*
2) Communicates with the Bulk CCR operator of any unit rate changes or hydrogen venting to HRRS. The Hydro Department also controls venting rates of hydrogen.
3) Backs all Refinery Make Gas out of Unit-118 before starting shutdown.

NEW practice from 2012 shutdown to Reduce duration of PSA gas venting to the flare

4) *Allows the PSA to trip automatically and not manually. An automatic trip sequence is initiated when the pressure of the incoming PSA feed gas drops below a prescribed limit. As part of the shutdown process, the flow of natural gas feed to the reformer is slowly reduced. When this occurs, the PSA inlet pressure decays. In the past, operators have manually tripped the PSA unit before the skid has reached its minimum operating pressure. A consequence of tripping the PSA unit is that all the feed gas bypasses the PSA and is sent to flare. By letting the PSA trip at the prescribed minimum pressure operations will minimize the time that PSA feed gas is sent to flare and it will recover more of the hydrogen product.*

5) Shuts down the vapor recovery compressors (GB151& GB152) only if controlled venting of Unit-118 is affecting fuel gas. Fuel Gas HHV must stay above 1050 BTU / SCF for proper burner functioning.
6) Reduces steam usage where possible during the Units-118 purge process.

D&C Department:

1) Closes the U-152 FCC DeEthanizer By-pass prior to the Unit 118 shutdown.
2) Communicates with the Utilities CCR operator of any unit rate changes or venting to HRS.
3) Reduces steam usage where possible during the Unit-118 outage.

Flare Minimization Guideline: Shutdown of Carson Hydrotreating Units

Describe Change:

- Controlled shutdown of the HDT and/or DHT-3 for a Turnaround.

Consequence of Change:

- Flaring may occur due to possible high fuel gas pressure during Hydrotreating unit shutdown.

The guidelines below are followed prior to or during shutting down the hydrotreating units. These measures will minimize the impact to the fuel system pressure and minimize flaring:

Bulk Department:

1) Coordinate the increase of steam usage throughout the Carson facility while staying within one boiler capacity.
2) Shutdown LPG vaporizer if operating.

East Department:

1) Have Coker reduce rate to decrease Coker Dry Gas production.
2) Increase steam usage as requested.
3) Communicate with Bulk for any change in steam usage.

West Department:

1) Communicate with Bulk and East of HDT or DHT-3 shutdown.

New practice from 2012 turnaround to minimize H_2S contamination and venting volumes

2) *Maximize product recycle to reduce sulfur content in the unit. Replace feed with Straight Run Gas Oil. Following the H_2 strip and cool down of reactors, maximize H_2 purge and the fresh H_2 makeup to minimize H_2S content of recycle H_2 gas.*
3) *Depressure hydrocarbons at a rate within Flare Gas Recovery limits, and reduce the vent rate if the header pressure reaches 1.5 psig. Drain levels to liquid flare after the HPLT separators reach approximately 100 psig. Continue depressurization until HPLT is approximately 10 psig. Block in the vent to the HRS when pressure is below 10 psig.*
4) *FOR HDT ONLY: Isolate the West Flare from FGR compressors and flare system.*
5) *Pressure and purge high and low pressure systems with nitrogen as required.*
6) *Vent off-gas to flare through DEA contactor until monitoring confirms the absence of H_2S.*
7) *Control steam-out of high and low pressure system within the confines of the water removal capacity of the flare system.*
8) Increase steam usage as requested during venting and purging.

Attachment A
Detailed Process Flow Diagrams
Not included in Public Review Copy

(Submitted with Confidential Business Section to AQMD, March 2013)