

**TECHNICAL SUPPORT DOCUMENT
AND STATEMENT OF BASIS
FOR CONSTRUCTION OF
ARIZONA CLEAN FUELS YUMA, LLC
PETROLEUM REFINERY
Permit Number 40140**

May 26, 2006

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I. INTRODUCTION

The proposed Class I / Title V Permit No. 40140 is for the proposed Arizona Clean Fuels Yuma, LLC petroleum refinery, a major stationary source. The proposed refinery will be located on an approximately 1,450-acre site, 40 miles east of Yuma, near the town of Tacna, in Yuma County. The proposed refinery will have the capacity to refine approximately 150,000 barrels per day (BPD) (6.3 million gallons per day) of crude oil and natural gasoline. The primary products of the refinery would be gasoline, jet fuel, propane, and diesel fuel.

This facility was issued a permit (#1001205) on April 14, 2005. In accordance with A.A.C. R18-2-402(D)(2), the company had an 18-month window to commence construction of the facility. The company has notified the Department that they will be unable to meet this deadline and has requested that the Department re-issue the permit for a new five-year term with a new 18-month construction window.

In order to retain the authorization to begin construction, the Permittee submitted a permit renewal application dated April 28, 2006. The Department has reviewed this application and is proposing to renew the permit without any significant revisions.

Pursuant to A.A.C. R18-2-322(A), renewal of a Class I permit “is subject to the same procedural requirements, including any for public participation and affected states and Administrator review, that would apply to that permit's initial issuance.”

Under U.S. EPA policy, because there is no emissions increase and no fundamental change in permitted equipment, the proposed permit renewal constitutes an “administrative” change to the Prevention of Significant Deterioration (PSD) permit. The only substantive review suggested by the U.S. EPA policy is that necessary to ensure that the permit reflects current Best Available Control Technology (BACT) requirements. The Department has performed such review and has determined that the current permit reflects current BACT. Specifically, the Department's review considered the following:

- Recent permitting actions for petroleum refinery expansion projects in several states;
- A recent PSD permit application for a petroleum refinery expansion project not yet permitted;
- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA; and
- Air pollution control equipment capital and operating cost data.

This review showed that no new, more effective air pollution control technologies applicable to the proposed refinery's emissions units have been recently demonstrated; no more stringent emission limitations applicable to the proposed refinery's emissions units have been recently demonstrated to be achievable; and there has been no reduction in expected adverse impacts from air pollution control devices rejected as BACT due to

unacceptable economic, environmental, or energy impacts.

In addition to the BACT review suggested by U.S. EPA policy, the Department also has performed a brief review of the information considered in the original air quality impact analyses. As a result of this review, the Department has determined that there have been no significant changes in air quality at the proposed refinery's location, and the prior determination of no anticipated adverse impacts remains valid.

A. Company Information

Facility Name: Arizona Clean Fuels Yuma, LLC
Mailing Address: Old Highway 80
Tacna, Arizona 85352
Facility Location: North of Interstate 8 between Avenues 44E and 46E
Yuma County, Arizona

B. Attainment Classification (Source: 40 CFR § 81.303)

The air quality control region in which the subject facility is located either is unclassified or is classified as being in attainment of the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants: particulate matter less than 2.5 microns (PM_{2.5}), particulate matter less than 10 microns (PM₁₀), nitrogen dioxide (NO₂), sulfur oxides (SO_x), carbon monoxide (CO), lead (Pb), and ozone (O₃).

II. PROCESS DESCRIPTION

Arizona Clean Fuels Yuma, LLC (hereinafter, "Arizona Clean Fuels") is a proposed petroleum refinery that will operate under Standard Industrial Code (SIC) 2911. The facility will operate 24 hours a day and 365 days a year.

The proposed refinery will have the capacity to refine approximately 150,000 BPD (6.3 million gallons per day) of crude oil and natural gasoline. Additional raw materials for the refining process may include natural gas, propane, and butane. Other inputs include natural gas, for use as supplemental fuel within the refinery, and products such as alkylate and oxygenates, for blending into the gasoline produced at the refinery.

This proposed refinery will supply cleaner-burning gasolines and other fuels to the Arizona market. The product slate of the proposed refinery consists of regular and premium reformulated gasolines, regular and premium gasolines meeting the stringent specifications of the California Air Resource Board (CARB), liquified petroleum gas (LPG), aviation jet fuel, and diesel fuel. A sulfur recovery plant (SRP) will capture sulfur contained in the crude oil feedstock and produce liquid sulfur product. In addition, the proposed refinery configuration includes a Delayed Coker Unit for the production of petroleum coke, a solid by-product that can be sold as a fuel.

The design of the proposed refinery utilizes current technologies that incorporate means to reduce air emissions. Throughout the design process, air emission reduction measures have been included to meet or exceed stringent federal standards that apply only to new refineries. Per unit of product, the planned refinery will have lower emissions of criteria pollutants than comparable older, existing refineries. The pollution control measures, including extensive monitoring and record keeping to be implemented at the facility are described in this technical support document.

This project represents the first facility in the western United States to be built specifically for the production of newer clean fuels. Several specialized commercial technologies are to be incorporated in the refinery process units to reduce fuel aromatics and sulfur, which in turn reduces emissions from vehicles. Because the proposed refinery has been designed specifically for the production of such fuels, it offers an economic source for the Arizona market of fuels meeting current and projected clean fuel specifications.

The proposed refinery will include numerous process units. These process units, and their interconnections within the facility, are shown in Figure II-A. The major process units include a Crude Distillation Unit, a Delayed Coking Unit, a Hydrocracker Unit, a Naphtha Hydrotreater Unit, a Distillate Hydrotreater Unit, a Catalytic Reforming Unit, a Butane Conversion Unit, a Benzene Reduction Unit, and an Isomerization Unit. Supporting process units include a Gas Concentration Plant, a Hydrogen Plant, a Sulfur Recovery Plant, an Amine Regeneration Unit, a Sour Water Stripper, and a Wastewater Treatment Plant.

Each of these process units comprises several distinct components such as distillation columns, reactors, fired heaters, heat exchangers, pumps, and compressors to achieve specific refining objectives. The capacities of these process units are presented in subsequent sections of this document.

A. Crude Distillation Unit

The function of the Crude Distillation Unit is to provide primary separation of the crude oil and natural gasoline feedstocks for subsequent processing by downstream units. The charge capacity of this unit is 142,000 BPD of crude oil and 10,000 BPD of natural gasoline.

Crude oil and natural gasoline are preheated by exchange with hot products, passed through an Electrostatic Desalter to remove entrained brine, and are heated further in the Atmospheric Crude Charge Heater. The heated feed is then routed to the Atmospheric Crude Distillation Column, where it is separated into five liquid products at approximately atmospheric pressure. The lightest (i.e., lowest boiling point) product is naphtha, which is processed in a Naphtha Stabilizer to remove light hydrocarbons. This yields a stabilized naphtha with a vapor pressure low enough for safe storage. The light hydrocarbons in the overhead streams from the Naphtha Stabilizer and the Atmospheric Crude Distillation Column are sent to the Gas Concentration Plant for recovery. Kerosene, diesel, and atmospheric gas oil (AGO) liquid products from the Atmospheric Crude Distillation Column are steam stripped to control flash point. Condensed stripping steam (including a small quantity of hydrogen sulfide) is recovered in the column overhead system and is sent to the sour water collection system. Atmospheric residuum is the remaining liquid fraction and is composed of predominantly high boiling point components. This material is withdrawn from the bottom of the Atmospheric Crude Distillation Column.

The atmospheric residuum from the Atmospheric Crude Distillation Column is heated in the Vacuum Crude Charge Heater, where it is partially vaporized. The two-phase feed then enters the flash zone of the Vacuum Crude Distillation Column where it is distilled under vacuum conditions to prevent thermal decomposition. Light and heavy vacuum gas oil (LVGO and HVGO) are produced as liquid products. Vacuum residuum is the remaining liquid fraction and is withdrawn from the bottom of the column. This vacuum residuum material can be used as feed material in the Delayed Coking Unit or can be sold as asphalt. Condensed stripping steam (including a small quantity of hydrogen sulfide) is recovered in the column overhead system and is sent to the sour water collection system.

Products of the Crude Distillation Unit and the Vacuum Unit are referred to as “straight-run” products because they have not yet been subjected to either thermal or catalytic conversion processes.

B. Gas Concentration Plant

Light ends (i.e., gaseous, low boiling-point hydrocarbon streams) are produced as by-products from several process units at the proposed refinery. These light ends are routed to the Gas Concentration Plant, where propane and butane are recovered as finished products. Ethane and lighter hydrocarbons are treated to produce a gas stream suitable for use as refinery fuel. Pentane and heavier components are recycled to the Crude Distillation Unit for recovery as naphtha. The nominal design capacity of the Gas Concentration Plant is 13,000 BPD of propane and butane products.

The primary sources of light ends fed to the Gas Concentration Plant include:

- Overhead vapor from the Crude Distillation Unit and its Naphtha Stabilizer;
- Offgas or purge streams from the Naphtha Hydrotreater Unit, Distillate Hydrotreater Unit, and Hydrocracker Unit;
- Hydrocarbon gas produced as the result of thermal cracking at the Crude Distillation Unit and Delayed Coking Unit; and
- Debutanizer overhead products from the Catalytic Reforming Unit and Hydrocracker Unit.

Sulfur in the form of hydrogen sulfide (H_2S) is removed from the feed streams by counter-current absorption with an aqueous amine solution in three contactor columns. The H_2S -rich amine is sent to the Amine Regeneration Unit for regeneration and returned to the gas plant as lean amine. Sulfur in the form of mercaptans is removed from the propane and butane products by reaction with caustic soda in the Caustic Treater Unit. The mercaptan sulfur leaves the refinery as a solute in the spent caustic.

The fractionation objectives are achieved in three steam-reboiled columns operating in series: the De-ethanizer, Depropanizer, and Debutanizer. There are no fired heaters in the Gas Concentration Plant.

C. Hydrocracker Unit

The Hydrocracker Unit processes gas oil, primarily from the Crude Distillation Unit and the Delayed Coking Unit, to convert it into gasoline, jet, and diesel blendstocks. The nominal design charge capacity of this unit is 40,000 BPD of gas oil.

The gas oil feed streams are mixed with recycle and make-up hydrogen and are then heated in a gas-fired charge heater. The heated feed enters a series of two fixed-bed reactors where the hydrocracking reactions occur under conditions of high pressure and high temperature. The reactors contain fixed beds of aluminum

catalyst impregnated with noble metals. The catalyst must be regenerated approximately every 18 to 24 months to remove carbon deposits and other catalyst deactivators. For regeneration, the unit is shut down and the catalyst is removed from the unit and regenerated off-site.

In the hydrocracking reactions, the cracked, unsaturated hydrocarbons (e.g., olefins) are converted to completely saturated species (e.g. paraffins). The hydrogen also combines with sulfur and nitrogen to produce hydrogen sulfide and ammonia, which can then be removed. Hot reactor effluent gas is washed with water, and is then scrubbed in an amine contactor to remove hydrogen sulfide and ammonia. The scrubbed gas is compressed and returned to the reactor section for additional conversion. Condensed stripping steam and wash water are sent to the sour water collection system. Amine, rich with hydrogen sulfide, is sent to the Amine Regeneration Unit.

The hydrocarbon liquid effluent from the hydrocracking reactors is sent to a group of fractionators where the various product streams are separated. The first fractionator in this chain has a gas-fired feed heater. Subsequent fractionators operate at successively lower temperature ranges, and have steam-heated reboilers. Products from the fractionators include off-gases which contribute to the refinery fuel gas supply, gaseous light-ends that are routed to the Gas Concentration Plant, light and heavy naphtha supplied to the gasoline blending operation, kerosene, diesel, and an internal recycle stream (fractionator bottoms).

D. Naphtha Hydrotreater Unit

The Naphtha Hydrotreater Unit pre-treats naphtha streams prior to the streams being processed in the Catalytic Reforming Unit and the Isomerization Unit. The Naphtha Hydrotreater Unit removes contaminants such as sulfur, nitrogen, and oxygen by promoting hydrogenation reactions (i.e. addition of hydrogen to the hydrocarbon chain) in a fixed bed reactor containing nickel/molybdenum-promoted aluminum catalyst. The nominal design charge capacity of the Naphtha Hydrotreater Unit is 32,000 BPD of naphtha.

Naphtha streams are fed to the Naphtha Hydrotreater Unit from the Crude Distillation Unit, the Gas Concentration Plant, the Distillate Hydrotreater Unit, and the Delayed Coking Unit. The mixed liquid naphtha streams are mixed with recycle and make-up hydrogen, heated in the Naphtha Hydrotreater Charge Heater, and passed over the catalyst bed. The hydrogen reacts with the sulfur and nitrogen contaminants to produce hydrogen sulfide and ammonia. Some of this hydrogen sulfide and ammonia is absorbed in a water wash section just downstream of the reactor. The resulting sour water product is collected in a separator and sent to the sour water collection system. The reactor effluent is separated into fuel gas and light and heavy naphtha in the Stripper and Naphtha Splitter fractionation columns. The fuel gas is routed to the Gas Concentration Plant for further processing. Light naphtha and heavy naphtha are sent to the

Isomerization Unit and Catalytic Reforming Unit, respectively, for further treatment.

E. Catalytic Reforming Unit

The Catalytic Reforming Unit processes the heavy naphtha stream to make it more suitable for the production of motor gasoline. The nominal design charge capacity of this unit is 30,000 BPD of heavy naphtha.

The reforming process involves chemically rearranging the hydrocarbon molecules to produce higher-octane materials. [The octane number is a key measure of motor gasoline performance. The Catalytic Reforming Unit can produce reformate of up to 102 research octane number (RON-Clear).] Hydrogen gas is produced as a by-product of reforming, and is used as feed to the Naphtha Hydrotreater Unit, Distillate Hydrotreater Unit, Hydrocracker Unit, and Isomerization Unit.

The heavy naphtha feed streams, primarily from the Naphtha Hydrotreater Unit and Hydrocracker Unit, are mixed with recycle hydrogen and are passed through three reactors in series. Each reactor is preceded by a gas-fired feed heater. The reformed naphtha product (reformate) is separated from the by-product hydrogen. A portion of the hydrogen is compressed and recycled to be mixed with heavy naphtha feed material. The remaining hydrogen is compressed for use in other refinery processing units.

The reformate product is fractionated in the debutanizer for separation of light ends, which are sent to the Gas Concentration Plant for recovery. The reformate liquid product is sent to storage, for use in motor gasoline blending. Heat is provided to the debutanizer through the gas-fired Debutanizer Reboiler.

The Catalytic Reforming Unit reactor catalyst is continuously regenerated in the Catalytic Reforming Unit Catalyst Regenerator. Catalyst regeneration takes place in dedicated equipment and uses nitrogen, air, and perchloroethylene as regenerating agents. The Catalyst Regenerator performs two principal functions – solid catalyst regeneration and circulation. Spent catalyst from the final Catalytic Reforming Unit reactor vessel is conveyed to the Catalyst Regenerator, where it is regenerated in four steps: 1) coke burning with oxygen, 2) oxychlorination with oxygen and chloride, 3) catalyst drying with air/nitrogen, and 4) reduction of catalyst metals to “reduced” oxidation states. Exiting the Catalyst Regenerator, the regenerated catalyst is conveyed back into the first Catalytic Reforming Unit reactor.

Small quantities of hydrochloric acid and chlorine are generated in the Catalyst Regenerator. The vent gas from the Catalyst Regenerator is scrubbed in two stages with caustic solution and water in the Vent Gas Wash Tower for removal

of acid gases, in particular hydrochloric acid. From the Wash Tower, the cleaned vent gas is discharged to the atmosphere.

F. Isomerization Unit

The Isomerization Unit processes the light naphtha stream to produce a liquid product, called “isomerate,” which is more suitable for the production of motor gasoline. The nominal design charge capacity of this unit is 18,000 BPD of light naphtha.

The Isomerization Unit increases the octane number of the light naphtha stream. [The octane number is a key measure of motor gasoline performance. The Isomerization Unit typically produces isomerate with a research octane number (RON-clear) of 83 to 85.] Hydrogen gas is produced as a by-product of reforming, and is used as feed to the Naphtha Hydrotreater Unit, Distillate Hydrotreater Unit, Hydrocracker Unit, and Isomerization Unit.

Heated light naphtha is mixed with hydrogen gas and a small amount of chloride reagent, and is then passed through two fixed bed catalytic reactors in series. The reactor effluent is separated in the Stabilizer fractionation column into fuel gas and isomerate. The fuel gas stream is scrubbed with caustic solution and water to remove acid gases, and is then routed to the Gas Concentration Plant for processing. The isomerate is sent to storage for use in motor gasoline blending.

G. Distillate Hydrotreater Unit

The Distillate Hydrotreater Unit reduces the levels of sulfur and other contaminants in kerosene and diesel fuel products to meet regulatory specifications. The nominal design charge capacity of this unit is 34,000 BPD of distillate feedstock. The unit will be capable of reducing the sulfur content in the liquid fuel products to less than 0.05 percent by weight.

The distillate feedstocks, including straight-run kerosene and diesel liquid streams from the Crude Distillation Unit and distillate from the Delayed Coking Unit, are mixed with recycle hydrogen and heated to the reaction temperature in a gas-fired heater. The feed mixture is passed over two reactor beds with inter-bed quench. To promote different reactions, one bed contains a cobalt-molybdenum catalyst and the other contains a nickel-molybdenum catalyst.

Hydrogen sulfide and ammonia by-products are removed in a water wash section and an amine contactor downstream of the reactor. The aqueous wash fraction containing some hydrogen sulfide and ammonia is removed in a Separator, and routed to the sour water collection system. The H₂S-rich amine from the contactor is sent to the Amine Regeneration Unit for regeneration before being returned to the recycle gas scrubber as lean amine.

Liquid organic effluent from the reactor is steam stripped to remove light end hydrocarbons, which are routed to the Gas Concentration Plant for processing. The remaining hydrocarbon stream is separated into naphtha, kerosene, and diesel fractions in a fractionator column with a gas-fired reboiler. Naphtha-cut boiling point material is removed as the overhead stream and is sent to the Naphtha Hydrotreater Unit. The hydrotreated kerosene and diesel streams are sent to storage for use in jet fuel and diesel fuel blending.

H. Butane Conversion Unit

The proposed refinery will include a Butane Conversion Unit utilizing proprietary “InAlk” technology. This process uses a mixed C3/C4 feedstock material.¹ It produces both a low vapor pressure alkylate stream and a high-octane “polygasoline” stream for fuel blending. The nominal design charge capacity of this unit is 28,000 BPD of mixed C3/C4 feedstock.

Mixed C3/C4 feed, primarily from the Gas Concentration Plant, enters the process at the Isostripper, which has a gas-fired reboiler. Polymerization of C4 materials is enhanced by treatment of a side stream from the Isostripper in the Butamer reactor. This catalytic reactor uses a platinum-containing catalyst to produce an increased quantity of isobutane, which is returned to the Isostripper. Off-gas from the Butamer reactor, which contains light ends, can be recycled to the Gas Concentration Plant or can be used as refinery fuel gas (RFG).

The overhead stream from the Isostripper, which is enriched in isobutane, is processed in the Dehydrogenation Reactor. The isobutane stream is mixed with recycle hydrogen and heated in a gas-fired charge heater. Dehydrogenation takes place in a multi-stage, catalytic reactor having a gas-fired interheater. In the reactor effluent stream, the C3/C4 components are separated from residual hydrogen, a portion of which forms the recycle stream.

After preheating, the reactor effluent is compressed and passed through a Separator to remove excess hydrogen before being fed to a catalytic condensation reactor that polymerizes these molecules to form a C8 to C12 product blend. Under proper conditions, normal butane and isobutane can be selectively polymerized to form an iso-octane product with a high octane number for gasoline blending. The Stabilizer column separates this octane product from unreacted C3/C4 material.

¹ Hydrocarbon materials in the petroleum refining industry are frequently classified and described based on the number of carbon atoms per molecule. For example, “C3” refers to materials with three carbon atoms per molecule, such as propane (C₃H₈) and propylene (C₃H₆); “C4” refers to materials with four carbon atoms per molecule, such as butane (C₄H₁₀) and butylene (C₄H₈).

Catalyst used in the dehydrogenation reactor is continuously regenerated by the Butane Conversion Unit Catalyst Regenerator. Catalyst regeneration takes place in dedicated equipment and uses nitrogen, air, and perchloroethylene as regenerating agents. The Catalyst Regenerator performs two principal functions – solid catalyst regeneration and circulation. Spent catalyst from the final dehydrogenation reactor bed is conveyed to the Catalyst Regenerator. In this unit, spent catalyst is regenerated in four steps: 1) coke burning with oxygen, 2) oxychlorination with oxygen and chloride, 3) catalyst drying with air/nitrogen, and 4) reduction of catalyst metal to “reduced” oxidation states. Exiting the regeneration vessel, the regenerated catalyst is conveyed back into the first dehydrogenation bed. In this manner, freshly-regenerated catalyst is continuously circulated through the dehydrogenation reactors.

Small quantities of hydrochloric acid and chlorine are generated in the regeneration processes. The vent gas from the Catalyst Regenerator is scrubbed with caustic solution and water in a Vent Gas Wash Tower for removal of acid gases, in particular hydrochloric acid. From the Wash Tower, the cleaned vent gas is discharged to the atmosphere.

I. Benzene Reduction Unit

The proposed refinery will include a Benzene Reduction Unit using proprietary “BenSat” technology to reduce the content of aromatics, such as benzene, in materials used as gasoline blending components. The nominal design charge capacity of this unit is 14,000 BPD of naphtha or reformat.

Depending upon product requirements, the Benzene Reduction Unit can process light naphtha from the Naphtha Hydrotreater Unit, straight run naphtha from the Crude Distillation Unit, or light reformat streams. The initial step in the Benzene Reduction Unit is selective reaction of benzene (C_6H_6) in a Saturation Reactor. Hydrogen is fed with the hydrocarbon stream in slightly above stoichiometric amounts to promote benzene saturation. A Sulfur Guard Bed is provided to adsorb sulfur compounds from the feed and avoid sulfur poisoning of the reactor catalyst.

Downstream of the Saturation Reactor is a Stabilizer column that separates the liquid hydrocarbon stream, now enriched in saturated C6 compounds, from light ends and residual hydrogen.

Both the Reactor Preheater and Stabilizer Reboiler are steam heated. There are no fired heaters within the Benzene Reduction Unit.

J. Delayed Coking Unit

The Delayed Coking Unit processes vacuum residuum oil and other heavy crude

oil components using a thermal cracking process to produce lighter liquid products and solid coke. The nominal design charge capacity of this unit is 32,000 BPD of vacuum residuum feed.

The Delayed Coking Unit uses a semi-continuous process and employs two parallel coke drums. These coke drums are alternately switched on-line and off-line after filling with coke.

The primary feed material for the Delayed Coking Unit is vacuum residuum, which is the Vacuum Crude Distillation Column bottoms product from the Crude Distillation Unit. The feed material enters the bottom of the coker main fractionator where it mixes with condensed recycle material in the column. The combined stream is heated in one of the gas-fired coker charge heaters to initiate coke formation in the corresponding coke drum.

Coke drum overhead vapor, the product of the thermal cracking reactions during coking, flows back to the coker main fractionator. This column separates the coke drum overhead vapor into various light hydrocarbon constituents to be returned to other refinery process units. These include coker naphtha, which is sent to the Naphtha Hydrotreater Unit for further processing into gasoline blendstocks; light coker gas oil, which is sent to the Distillate Hydrotreater Unit for further processing into jet and diesel blendstocks; and heavy coker gas oil, which is sent to the Hydrocracker Unit for conversion and upgrade to additional gasoline and distillate fuel products. Sour water is sent to the sour water collection system.

After coking reactions are complete, the full coke drum is switched off-line and is steamed out and cooled. (The other coke drum is brought on-line and the coking process continues in that reactor train.) Vapors emitted from the opened coke drum are captured by the enclosed blowdown system and are recovered in the main fractionator. When cool, the coke drum bottom and top heads are removed. The coke is cut from the drum with a water jet and dropped into the Coke Pit.

K. Petroleum Coke Storage, Handling, and Loading

Petroleum coke from the Delayed Coking Unit is dropped into the Coke Pit. In the Coke Pit, free water is separated from the coke and recycled. A bridge crane is used to transfer the moist coke from the Coke Pit to the Coke Pad, where it is stored in piles. A bridge crane is also used to transfer coke from the Coke Pad to the Coke Crusher. The crushed, moist coke is then transferred via an enclosed belt conveyor to the Coke Silo.

Coke from the Delayed Coking Unit is transferred via an enclosed belt conveyor to the Coke Loading Facility. This facility includes a coke storage silo and a coke railcar loading operation.

L. Amine Regeneration Unit

Rich amine solution from the Gas Concentration Plant, Distillate Hydrotreater Unit, and Hydrocracker Unit is circulated to the Amine Regeneration Unit for regeneration. The Amine Regenerator is a liquid stripper column with a steam-heated reboiler. Mixed rich amine solutions are fed to the column yielding an overhead product rich in H_2S (i.e., “acid gas”) that is routed to the Sulfur Recovery Plant as feed. The stripped amine bottoms liquid is cooled and filtered and then recycled back to a storage tank as lean amine. This nitrogen-blanketed storage tank supplies make-up solution to the various amine contactors in the Gas Concentration Plant, Distillate Hydrotreater Unit, and Hydrocracker Unit, and contains the amine solution inventory during a shutdown. There are no fired heaters in the Amine Regeneration Unit.

M. Sour Water Stripper

Sour water streams containing H_2S , other organic sulfur compounds, ammonia (NH_3), and oil, are collected from various refinery process units and combined in a feed surge tank. Liquid hydrocarbons are decanted from the water and returned to the recovered oil tank. The Sour Water Stripper (SWS) removes H_2S / NH_3 from the sour water using a stripper tower having a steam-heated reboiler.

Feed sour water is preheated by exchange with the stripper bottoms stream. The reboiler is heated with low-pressure steam to generate vapor traffic up the stripper column. Vaporization of water strips H_2S and NH_3 from the downcoming sour water. Overhead vapors are cooled by an overhead condenser. Condensed water reflux is returned to the top tray in the stripper tower. The overhead, non-condensable materials, primarily H_2S and NH_3 , are routed to the Sulfur Recovery Unit as feed. The stripped water is reused at the crude desalters and at process units requiring wash water (e.g., for ammonia removal). Any remaining stripped water is routed to the Wastewater Treatment Plant. There are no fired heaters associated with the Sour Water Stripper.

N. Sulfur Recovery Plant

The Sulfur Recovery Plant provides for safe disposal of the acid gas product streams from the Sour Water Stripper and the Amine Regeneration Unit. The plant comprises three processing steps: two parallel Claus sulfur recovery units, a tail gas treatment unit (TGTU), and a tail gas thermal oxidizer. The capacity of the Sulfur Recovery Plant is 608 long tons per day of liquid elemental sulfur product.

Each Claus sulfur recovery unit (SRU) uses a three-stage reactor train to convert approximately 94 to 97 percent of the feed sulfur into elemental sulfur. The TGTU uses catalytic reduction and amine absorption technology to recover

additional sulfur compounds from the Claus SRU tail gas and recycles them back to the SRU. The unrecovered sulfur compounds are oxidized to sulfur dioxide (SO₂) in the tail gas thermal oxidizer.

For reliability, two complete 3-stage Claus trains are employed in the proposed refinery design; each normally operated at 67 percent of maximum acid gas throughput capacity. In the first (non-catalytic) reaction furnace section, ammonia is converted to nitrogen and water, and a portion of the H₂S is converted to SO₂ and water. The acid gas then flows through two catalyst beds in series where the Claus reaction occurs (H₂S and SO₂ partially react to form sulfur). The sulfur in the vapors from the thermal section and each of the three catalyst beds are condensed and flow through seal legs to a covered tank termed the "Sulfur Pit." The vapor from the last sulfur condenser then flows to the TGTU.

Liquid sulfur in the Sulfur Pit is loaded into tank trucks or tank cars for sale. A steam-powered ejector draws sweep-air through the headspace of the Sulfur Pit tank to capture vapors containing reduced sulfur compounds. This sweep-air stream is routed to the inlet of the Claus SRU trains for recovery of the sulfur. There is no point in the SRU process when solid sulfur is produced or handled.

Tail gas exiting the last stage of Claus SRU is combined with hydrogen or methane (natural gas) and passed through the TGTU Reducing Reactor and a catalytic Hydrogenation Reactor to convert the residual sulfur dioxide back to H₂S. Downstream of these reactors, additional recovery of reduced sulfur is accomplished in an amine absorber column that uses an aqueous methyl diethanolamine (MDEA) solvent to scrub H₂S from the TGTU tail gas. The overhead stream from this contactor, containing very low sulfur levels, is sent to the tail gas thermal oxidizer for disposal. The rich MDEA solvent is regenerated in the TGTU amine stripper and H₂S is returned to the inlet of the Claus SRU trains to be recovered. Regenerated MDEA solvent is recirculated back to the TGTU amine absorber column.

There will be instances when upset conditions or maintenance events at the Sulfur Recovery Plant are such that compliance with the SO₂ emission limitations cannot be maintained indefinitely. The proposed refinery design includes several measures intended to avoid excess emissions during these periods. First, the Claus SRU trains are designed with excess capacity. In the event of an upset condition or maintenance event on one of the Claus SRU trains, the other train will be operated at full capacity. Second, the Sour Water Tank will be sized to provide continuously available sour water storage capacity of at least 3.78 million gallons. This will allow the feed to the Sour Water Stripper to cease for at least 24 hours, while the refinery process units continue operating and generating sour water streams. The cessation of Sour Water Stripper operations can be implemented within minutes, so that excess emissions are minimized even during unplanned outages of a Claus SRU train or the TGTU. Third, the Rich Amine Tank will be sized to provide continuously available rich amine storage capacity

of at least 210,000 gallons, and the Lean Amine Tank will be sized and the lean amine solution will be managed to provide a continuously available supply of at least 210,000 gallons. These measures will allow the feed to the Amine Regeneration Unit to cease for a minimum of 24 hours, while the refinery process units continue operating and generating rich amine solution. The cessation of Amine Regeneration Unit operations also can be implemented within minutes, so that excess emissions are minimized even during unplanned outages of a Claus SRU train or the TGTU. When implemented simultaneously, these measures can reduce or stop the processing of acid gas in the Claus SRU trains during outages of the TGTU or both Claus SRU trains. For longer-term outages of a single Claus SRU train, to avoid exceeding the acid gas processing capability of a single train, reduced sulfur crude oil would be inventoried at the plant and could be used to substitute some or all of the normal feed to the refinery process units.

O. Hydrogen Plant

The Hydrogen Plant will manufacture hydrogen by converting light hydrocarbons into hydrogen using a steam reforming process. The plant can use as feedstock either natural gas, a mixture of RFG and natural gas, a mixture of RFG and propane, or a mixture of RFG and butane. The nominal design capacity of this plant is 120 million standard cubic feet per day of hydrogen with purity in excess of 99.9 percent.

The Hydrogen Plant conversion process consists of four steps: feed pretreatment, steam reforming, shift-reaction conversion, and purification. The feed pretreatment step removes or converts contaminants in the feedstock that would otherwise poison or damage downstream catalysts. Next, the feed is combined with steam and is fed to the Hydrogen Reformer (also called the Steam-Methane Reformer). This process unit consists of a group of catalyst-packed tubular reactors within a gas-fired furnace that is maintained at the proper reaction temperature. Within the catalyst tubes, steam and hydrocarbons react to form hydrogen and carbon dioxide. The reactor effluent is cooled in a steam boiler and heat exchanger before being fed to a fixed-bed Shift Reactor, which drives the reaction to a greater extent of completion. High purity hydrogen is separated from the reactor effluent in a Pressure Swing Adsorption (PSA) unit. The PSA purge is routed to the Hydrogen Reformer Heater as fuel. The PSA purge gas, supplemented by RFG, is combusted in the reformer furnace containing the catalyst-filled reactor tubes.

P. Group “A” Storage Tanks

The Tank Farm includes eight dome-roof storage tanks that are equipped with nitrogen blanket systems and closed-vent systems vented to a compression system. For the purposes of the proposed Class I permit, due to their similar configuration and similar regulatory applicability, these storage tanks are grouped

for administrative convenience.

The compressed vapors from the Group “A” Storage Tanks are routed to the RFG system. These storage tanks are designed to store raw materials and intermediates such as natural gasoline, isomate, light naphtha, vacuum residuum, and slop oil.

Q. Group “B” Storage Tanks

The Tank Farm includes forty-seven fixed-roof storage tanks that are equipped with internal floating roofs and closed-vent systems vented to a thermal oxidizer. These storage tanks are designed to store organic liquids such as crude oil, gas oil, light and heavy naphtha, alkylate, reformate, gasoline, jet fuel, diesel fuel, and ethanol. For the purposes of the proposed Class I permit, due to their similar configuration and similar regulatory applicability, these storage tanks are grouped for administrative convenience.

R. Group “D” Storage Tanks

The Tank Farm includes six pressurized, spherical storage tanks that are designed to operate with no emissions. These storage tanks are designed to store volatile organic liquids such as butane, butylene, and liquefied petroleum gas. For the purposes of the proposed Class I permit, due to their similar configuration and similar regulatory applicability, these storage tanks are grouped for administrative convenience.

S. Group “E” Storage Tank

The Tank Farm includes one asphalt storage tank. This tank will be used to store asphalt that is produced at the proposed refinery.

T. Truck and Rail Car Loading Racks

The liquid products produced at the proposed refinery will be transported by rail cars and tank trucks. The proposed refinery will have two terminals for liquid transfer; one for railcar loading and unloading, and one for tank truck loading. Facilities for the loading and unloading of petroleum liquids have been designed to maximize the recovery of evaporative VOC emissions. Residual VOC emissions from loading of liquid products will be controlled using two thermal oxidizers, one serving the rail car loading racks and one serving the tank truck loading racks.

Each loading rack will have a maximum delivery rate of 600 gallons per minute (GPM) per loading arm. All gasoline product and distillate product loading racks are designed for bottom loading. LPG loading racks are designed for top loading. Displaced vapors from the LPG loading operations are routed back to storage.

U. Benzene Waste Operation

The Benzene Waste Operation comprises the refinery equipment used to manage aqueous and non-aqueous waste streams that contain benzene. This will include the equipment in the Wastewater Treatment Plant, and may include other equipment. For the purposes of the proposed Class I permit, equipment used for Benzene Waste Operations is grouped for administrative convenience, due to the unique regulatory requirements applicable to this equipment under subpart FF of 40 CFR part 61. Refer to Section IV.C.2 herein for a detailed discussion of this regulation.

V. Wastewater Treatment Plant

The wastewater treatment plant (WWTP) is designed to maximize water recycle and reuse. Treatment facilities include wastewater collection, primary treatment, secondary treatment, brine concentration, sludge treatment and sludge dewatering.

The treatment vessels and sumps comprising the WWTP will be enclosed tanks or similarly covered vessels. Open impoundments or uncovered tanks will not be used. Air drawn from the headspace of several WWTP vessels will be treated in a dedicated WWTP Thermal Oxidizer.

The wastewater collection system comprises a system of covered sewers for collection of oily wastewater. Oily water streams include de-salter water, crude and product tank water draws, and neutralized spent caustic. Other potentially oil-contaminated wastewater streams such as storm water from process units and tank farm dikes are collected on a “first flush basis” (i.e., the water that initially runs off an area). The remainder of the storm water runoff after the first flush and all other clean runoffs from other non-process surface drainage will be collected in the storm water pond for reuse as makeup water to the cooling tower.

The oily water sumps, which normally receive contaminated oily wastewater, will have double containment for spill prevention and leak detection. These sumps will be vented to the atmosphere either via a dedicated carbon adsorption system (i.e., “local carbon canister”) or via the WWTP Thermal Oxidizer.

The primary treatment system comprises an API separator (i.e., an oil-water separator designed in conformance with the specifications of the American Petroleum Institute), a dissolved air flotation (DAF) unit, and an equalization basin. Exhaust streams from these three vessels are routed to the WWTP Thermal Oxidizer. The primary treatment system is designed to remove free oil and suspended solids from the refinery wastewater. The API separator will be an above-ground enclosed rectangular vessel in which the wastewater flows horizontally while the free oil particles rise due to buoyancy forces. The free oil

floats to the surface of the tank and is skimmed into a slop oil compartment for recovery in the refinery. Solids settle in the bottom of the tank, where they are scraped into sludge hoppers by a flight scraper. The settled solids are removed from the sludge hopper by a sludge pump to an oily sludge tank for possible recycle to the Delayed Coking Unit.

Effluent from the API separator containing residual emulsified oil is further treated by the DAF unit. Wastewater is fed continuously at a controlled rate to the DAF system via the flocculation chamber. Polymer is added in the flocculation chamber to facilitate flocculation of the colloidal suspended solids and oil. A portion of the DAF clarified effluent is pressurized with air in the DAF saturation tank. The dissolved air flotation system blends recycled effluent saturated with air, at elevated pressure, with the incoming coagulated wastewater to release microscopic air bubbles that cling to the oil and solids particles forcing them to float to the top of the flotation cell where they are skimmed off as "float." Heavier solids settle in the bottom of the DAF and will be treated and dewatered prior to disposal. The DAF treated effluent flows by gravity through the DAF effluent chamber into the equalization basin, from which it is pumped to the secondary treatment system.

The secondary treatment system comprises an activated sludge biological treatment system (i.e., "biotreater"), a clarifier, a warm lime softener, and a reverse osmosis system. The activated sludge process in the biotreater is an aerobic biological treatment that involves the stabilization of organic matter by microorganisms, which oxidize organic compounds present in wastewater to carbon dioxide. Phosphoric acid is added to the wastewater stream to provide the nutrient phosphorus as required by the microorganisms in the biological aeration treatment system. Powdered activated carbon treatment provides added treatment by the addition of powder activated carbon to remove refractory and non-biodegradable organics in the wastewater. Exhaust from the biotreater is routed to the WWTP Thermal Oxidizer.

Mixed liquor (sludge and water) from the biotreater flows by gravity to the clarifier, where biosolids and powdered activated carbon settle to the bottom of the clarifier. Treated wastewater flows by gravity to the warm lime softener, where it is treated to remove silica and hardness by adding magnesium chloride, soda ash, and caustic. Effluent water from the warm lime softener is polished through multi-media filters and routed to the reverse osmosis system. Clean water from the reverse osmosis system is recycled for further use in the refinery.

A portion of the recovered mixture of biosolids and powdered activated carbon from the clarifier is recycled to the biotreater, while the remainder is sent to a wet air oxidation unit for the regeneration of powdered activated carbon. Regeneration of the powdered activated carbon is achieved by oxidizing the biosolids, in liquid phase, under high temperature and high pressure, using high-pressure steam as the heat source. (There is no fuel input to the wet air oxidation

unit.) Regenerated powdered activated carbon is recycled to the biotreater.

Ash from the wet air oxidization unit and sludge from the warm lime softener are routed to a belt press for dewatering prior to landfill disposal.

“Reject” water from the reverse osmosis system has elevated levels of dissolved solids and is known as brine solution. This brine solution is heated and routed to an induced-draft cooling tower for further concentration. The brine slurry from the concentration cooling tower is pumped to a spray dryer, which uses an integral natural gas-fired air heater. In the spray dryer, dissolved solids are recovered as a powdered salt material. Dry powder salt collected at the bottom of the spray dryer is conveyed pneumatically to a collection system and is placed in containers for offsite disposal. The pneumatic conveying system exhausts through a fabric filter baghouse.

W. Equipment Leaks

The proposed refinery includes piping and a large number of screwed and flanged connectors, valves, pumps, compressors, and similar components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of volatile organic compounds (VOC), hazardous air pollutants (HAPs), and H₂S emissions due to leakage.

X. Emergency Flares

The proposed refinery will include a pressure relief system designed to contain non-routine hydrocarbon releases and route these releases to two elevated flares. One flare (Refinery Flare 1) will be centrally located near most of the refinery process units, and the second (Refinery Flare 2) will be located near the Delayed Coking Unit. In the event of a process upset or a sudden shutdown that causes hydrocarbon material to be released from any of the pressure relief devices and emergency depressurizing equipment throughout the refinery, the emergency flares will safely combust the released material and discharge the combustion products to the atmosphere.

Each of the two elevated flares is nominally designed to combust 2.0 million pounds per hour of gases (based on gases having a design average molecular weight of 28 pounds per pound-mole and released at a design temperature of 236 degrees Fahrenheit (°F)). This reflects the estimated maximum process vessel venting case and corresponds to the emergency scenario of a total refinery power failure. Steam is supplied to the flare tip to allow smokeless operation up to a release rate of 300,000 pounds per hour, with a VOC destruction efficiency of approximately 98 percent, under design conditions.

The features of the flare design include a continuous natural gas pilot flame and

stack purge, and steam assist to improve VOC control and prevent soot formation. Pipeline natural gas is constantly purged up the flare stack column and is ignited at the top by the continuous pilot flame. This operation keeps the flare ready to immediately receive and safely combust released gases, without relying on pilot ignition. The pilot is continually monitored by remote camera or other means to confirm pilot operation, and to effect a restart of the pilot if necessary.

Y. Steam Boilers

Steam is distributed throughout the plant at three nominal pressure levels of 600 pressure per square inch gauge (psig), 150 psig, and 50 psig. Two boilers are to be constructed that will generate steam at 600 psig and 700°F. Each boiler has a rated heat input of 419 million British Thermal Units (MMBTU) per hour and will be fired exclusively with pipeline-quality natural gas. Each boiler is sized to provide approximately 50 percent of the maximum projected steam demand. It is planned that both boilers will be operated continuously, but generally at 40 to 50 percent of capacity, to provide hot standby capacity for emergencies. When required, one boiler can be shutdown for maintenance and inspection, and the other can operate at full capacity to meet the plant needs.

Z. Cooling Tower

Water will be used in several areas of the proposed refinery to remove process heat, condense vapor streams, and cool products before storage. Warm cooling water from the process areas is circulated through a direct-contact cooling tower. A fraction of the water evaporates and the circulating cooling water temperature is reduced. The cooled water is then pumped back to the process areas for re-use. Water lost to evaporation is replaced with make-up water. Cooling water use has been minimized in the proposed refinery design to minimize evaporative losses and thereby conserve water. The system is sized for a cooling water circulation rate of 80,000 GPM.

Emissions from the cooling tower include VOC, due to leaks in indirect contact heat exchangers in refinery process units, and particulate matter, due to residual solids in aerosol drift particles released from the tower that subsequently evaporated.

AA. Internal Combustion Engines

The proposed refinery will include an on-site emergency electrical generator and two on-site fire water pumps. Each will be driven by a compression-ignition, diesel-fired, internal combustion engine. The emergency electrical generator will allow for a safe and orderly shutdown of the refinery, or individual refinery process units, in case of an emergency. The fire water pumps will be used to pump water as needed for extinguishing fires. The emergency electrical generator

and the fire water pumps will also be operated for a few hours per month for routine testing and maintenance.

BB. Mobile Sources and Fugitive Dust Sources

The construction and operation of the proposed refinery will involve mobile sources and dust-generating operations such as land clearing, earthmoving, excavating, construction, demolition, material handling, storage or transporting operations, and vehicle use.

III. EMISSIONS

A. General

Table III-A presents a summary of pollutant emission rates from all emission units at the proposed refinery. Emissions from specific emission units, including emission calculation methodologies and tabular emission summaries, are presented in Sections III.A through III.P.

Table III-A. Emission Summary

Pollutant Source(s)	NO _x		SO ₂		CO		VOC		PM		PM ₁₀		hydrogen sulfide	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Process Heaters	60.68	265.76	22.66	99.25	155.86	682.68	15.59	68.27	29.22	128.00	29.22	128.00	0.92	4.04
Boilers	10.48	45.90	0.50	2.20	13.41	58.76	3.35	14.69	3.14	13.77	6.28	27.54	-----	-----
Sulfur Recovery Plant (incl. SRU Thermal Oxidizer)	6.00	26.28	33.60	147.17	8.40	36.79	0.55	2.41	0.76	3.33	0.76	3.33	0.09	0.39
Group "B" Storage Tanks (incl. Tank Farm Thermal Oxidizer)	2.25	9.86	0.33	1.43	4.73	20.71	57.48	13.09	0.43	1.87	0.43	1.87	0.01	0.06
Wastewater Treatment Plant (incl. WWTP Thermal Oxidizer)	0.03	0.15	0.00	0.01	0.03	0.12	8.06	35.33	0.00	0.01	0.00	0.01	0.00	0.00
Loading Racks (incl. Loading Rack Thermal Oxidizers)	2.47	10.80	0.14	0.62	2.07	9.07	27.81	12.81	0.19	0.82	0.19	0.82	0.01	0.03
Emergency Flares	0.11	0.50	0.00	0.00	0.62	2.70	0.10	0.46	-----	-----	-----	-----	-----	-----
Coke Silo Baghouse	-----	-----	-----	-----	-----	-----	-----	-----	0.09	0.41	0.09	0.41	-----	-----
WWTP Spray Dryer Baghouse	-----	-----	-----	-----	-----	-----	-----	-----	1.17	5.11	1.17	5.11	-----	-----
Catalyst Regenerator Vents	1.65	7.22	-----	-----	1.00	4.40	-----	-----	-----	-----	-----	-----	-----	-----
Cooling Tower	-----	-----	-----	-----	-----	-----	3.36	14.72	1.60	7.01	1.60	7.01	-----	-----
Equipment Leaks	-----	-----	-----	-----	-----	-----	16.82	13.18	-----	-----	-----	-----	0.27	1.22
Internal Combustion Engines	25.7	2.57	0.03	0.00	17.3	1.73	2.12	0.21	0.99	0.10	0.99	0.10	-----	-----
Vehicle Traffic on Paved Areas	-----	-----	-----	-----	-----	-----	-----	-----	3.52	7.71	0.69	1.50	-----	-----
SOURCE-WIDE TOTAL	115.38	395.54	57.26	250.66	203.39	816.96	135.24	175.16	44.26	181.92	41.43	175.71	1.50	6.61

Table III-A. Emission Summary (Continued)

Pollutant Source(s)	Ammonia		Acetaldehyde		Benzene		Benzo(a)pyrene		Chlorine	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Process Heaters	5.44	23.8	0.0095	0.041	0.24	1.1	0.000013	0.000058		----
Boilers	----	----	----	----	0.0018	0.0077	----	----	----	----
Sulfur Recovery Plant (incl. SRU Thermal Oxidizer)	----	----	0.00024	0.0011	0.0062	0.027	0.0000004	0.0000015	----	----
Group "B" Storage Tanks (incl. Tank Farm Thermal Oxidizer)	----	----	----	----	0.52	0.11	0.0000002	0.0000008	----	----
Wastewater Treatment Plant (incl. WWTP Thermal Oxidizer)	----	----	----	----	0.40	1.77	----	----	----	----
Loading Racks (incl. Loading Rack Thermal Oxidizers)	----	----	----	----	----	----	----	----	----	----
Emergency Flares	----	----	----	----	----	----	----	----	----	----
Coke Silo Baghouse	----	----	----	----	----	----	----	----	----	----
WWTP Spray Dryer Baghouse	----	----	----	----	----	----	----	----	----	----
Catalyst Regenerator Vents	----	----	----	----	----	----	----	----	0.12	0.52
Cooling Tower	----	----	----	----	0.04	0.18	----	----	----	----
Equipment Leaks	----	----	----	----	0.14	0.11	----	----	----	----
Internal Combustion Engines	----	----	----	----	----	----	----	----	----	----
Vehicle Traffic on Paved Areas	----	----	----	----	----	----	----	----	----	----
SOURCE-WIDE TOTAL	5.44	23.8	0.0097	0.042	1.26	3.31	0.000013	0.000058	0.12	0.52

Table III-A. Emission Summary (Continued)

Pollutant Source(s)	Chrysene		Ethylbenzene		Fluoranthene		Formaldehyde		Hexane	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Process Heaters	0.000010	0.000044	----	----	0.00012	0.00053	0.055	0.24	----	----
Boilers	----	----	----	----	0.0000025	0.000011	0.063	0.28	----	----
Sulfur Recovery Plant (incl. SRU Thermal Oxidizer)	0.0000003	0.0000011	----	----	0.0000031	0.000014	0.0014	0.0062	----	----
Group "B" Storage Tanks (incl. Tank Farm Thermal Oxidizer)	----	----	0.13	0.03	----	----	0.00079	0.0035	2.7	0.55
Wastewater Treatment Plant (incl. WWTP Thermal Oxidizer)	----	----	----	----	----	----	----	----	----	----
Loading Racks (incl. Loading Rack Thermal Oxidizers)	----	----	----	----	----	----	----	----	----	----
Emergency Flares	----	----	----	----	----	----	----	----	----	----
Coke Silo Baghouse	----	----	----	----	----	----	----	----	----	----
WWTP Spray Dryer Baghouse	----	----	----	----	----	----	----	----	----	----
Catalyst Regenerator Vents	----	----	----	----	----	----	----	----	----	----
Cooling Tower	----	----	----	----	----	----	----	----	----	----
Equipment Leaks	----	----	0.04	0.03	----	----	----	----	0.80	0.63
Internal Combustion Engines	----	----	----	----	----	----	----	----	----	----
Vehicle Traffic on Paved Areas	----	----	----	----	----	----	----	----	----	----
SOURCE-WIDE TOTAL	0.000010	0.000044	0.17	0.06	0.00013	0.00055	0.12	0.53	3.6	1.2

Table III-A. Emission Summary (Continued)

Pollutant Source(s)	Naphthalene		Perchloroethylene		Phenol		Toluene		Xylene	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Process Heaters	0.00076	0.0033	----	----	0.0034	0.015	0.33	1.40	----	----
Boilers	0.00051	0.0022	----	----	----	----	0.0029	0.012	----	----
Sulfur Recovery Plant (incl. SRU Thermal Oxidizer)	0.000019	0.000085	----	----	0.000086	0.00038	0.0084	0.037	----	----
Group "B" Storage Tanks (incl. Tank Farm Thermal Oxidizer)	----	----	----	----	----	----	1.2	0.25	0.44	0.09
Wastewater Treatment Plant (incl. WWTP Thermal Oxidizer)	----	----	----	----	----	----	----	----	----	----
Loading Racks (incl. Loading Rack Thermal Oxidizers)	----	----	----	----	----	----	----	----	----	----
Emergency Flares	----	----	----	----	----	----	----	----	----	----
Coke Silo Baghouse	----	----	----	----	----	----	----	----	----	----
WWTP Spray Dryer Baghouse	----	----	----	----	----	----	----	----	----	----
Catalyst Regenerator Vents	----	----	0.60	2.60	----	----	----	----	----	----
Cooling Tower	----	----	----	----	----	----	----	----	----	----
Equipment Leaks	----	----	----	----	----	----	0.35	0.29	0.13	0.10
Internal Combustion Engines	----	----	----	----	----	----	----	----	----	----
Vehicle Traffic on Paved Areas	----	----	----	----	----	----	----	----	----	----
SOURCE-WIDE TOTAL	0.0013	0.0056	0.60	2.60	0.0035	0.015	1.9	2.0	0.57	0.19

B. Process Heaters

Hourly and annual emissions from the process heaters at the proposed refinery are presented in Table III-B. Emissions of all pollutants from process heaters were calculated as the product of the permitted maximum heat input capacity, expressed in MMBtu/hr, and an emission factor, expressed in lb/MMBtu heat input. For example, NO_x emissions from the Atmospheric Crude Charge Heater were calculated as follows:

$$E_{\text{NO}_x} = \left(346 \frac{\text{MMBtu}}{\text{hr}} \right) \times \left(0.0125 \frac{\text{lb}}{\text{MMBtu}} \right) = 4.3 \text{ lb/hr}$$

All process heaters are permitted to operate at maximum heat input capacity, without restriction, on a year-round basis. Thus, annual emissions are calculated assuming the hourly emission rate for 8,760 hours per year.

Emission factors used to calculate emissions from process heaters are shown in Table III-B and were derived as follows:

- For NO_x, PM/PM₁₀, and CO, the permitted emission limit is expressed in lb/MMBtu heat input and is used directly.
- For SO₂, the emission factor is calculated using the permitted fuel sulfur limit of 35 ppmv. Other values required for the calculation of an emission factor in terms of lb/MMBtu heat input are a conservatively assumed RFG heating value of 1000 Btu per standard cubic foot; a molecular weight of 64.06 pounds per pound-mole for SO₂; and a physical constant of 385.55 standard cubic feet per pound-mole of gas. The calculation is as follows:

$$EF_{\text{SO}_2} = \frac{\left(35 \frac{\text{lb} \cdot \text{mol S}}{10^6 \text{ lb} \cdot \text{mol RFG}} \right) \times \left(64.06 \frac{\text{lb SO}_2}{\text{lb} \cdot \text{mol S}} \right)}{\left(385.55 \frac{10^6 \text{ scf RFG}}{10^6 \text{ lb} \cdot \text{mol RFG}} \right) \times \left(1,000 \frac{\text{MMBtu}}{10^6 \text{ scf RFG}} \right)} = 0.0058 \frac{\text{lb SO}_2}{\text{MMBtu}}$$

- For ammonia (NH₃), which is only emitted by the process heaters that are equipped with SCR, the emission factor is calculated using the permitted emission limit of 5.0 ppmvd, corrected to zero percent excess oxygen. Other values required for the calculation of an emission factor in terms of lb/MMBtu heat input are an assumed F-factor of 8,710 standard cubic foot of exhaust per MMBtu heat input from RFG; a molecular weight of 17.03 pounds per pound-mole for NH₃; and a physical constant of 385.55 standard cubic feet per pound-mole of gas. The calculation is as follows:

$$EF_{\text{NH}_3} = \frac{\left(\frac{5 \text{ lb} \cdot \text{mol NH}_3}{10^6 \text{ lb} \cdot \text{mol exhaust}} \right) \times \left(\frac{17.03 \text{ lb NH}_3}{\text{lb} \cdot \text{mol NH}_3} \right)}{\left(\frac{385.55 \text{ scf exhaust}}{\text{lb} \cdot \text{mol exhaust}} \right) \times \left(\frac{\text{MMBtu}}{8,710 \text{ scf exhaust}} \right)} = 0.0019 \frac{\text{lb NH}_3}{\text{MMBtu}}$$

- For VOC, the emission factor represents an engineering estimate of the emission rate achievable with the control strategy representing BACT. (As discussed in Section V.B.V below, no numerical BACT emission limit for VOC emissions from heaters is included in the proposed permit.)
- For H₂S and individual organic HAPs, the emission factor is taken from the California Air Toxics Emission Factors (CATEF) database, available at <http://www.arb.ca.gov/emisinv/catef/catef.htm>.

Table III-B. Process Heater Emissions

Emission Point No.	Description	Capacity (MMBtu/hr)	NO _x			SO ₂			CO			VOC			PM/PM ₁₀		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-1	Atm. Crude Heater	346	0.0125	4.3	18.9	0.0058	2.0	8.8	0.04	13.8	60.6	0.004	1.4	6.1	0.0075	2.6	11.4
	Vac. Crude Heater	100	0.0125	1.3	5.5	0.0058	0.6	2.6	0.04	4.0	17.6	0.004	0.4	1.8	0.0075	0.8	3.3
EP-2	Catalytic Reforming Unit Charge Heater	122	0.0125	1.5	6.7	0.0058	0.7	3.1	0.04	4.9	21.5	0.004	0.5	2.1	0.0075	0.9	4.0
	Catalytic Reforming Unit Interheater #1	192	0.0125	2.4	10.5	0.0058	1.1	4.9	0.04	7.7	33.7	0.004	0.8	3.4	0.0075	1.4	6.3
	Catalytic Reforming Unit Interheater #2	129	0.0125	1.6	7.1	0.0058	0.8	3.3	0.04	5.2	22.6	0.004	0.5	2.3	0.0075	1.0	4.2
EP-3	Catalytic Reforming Unit Debutanizer Reboiler	23	0.030	0.7	3.0	0.0058	0.1	0.6	0.04	0.9	4.1	0.004	0.1	0.4	0.0075	0.2	0.8
EP-4	Naphtha Hydrotreater Charge Heater	21.4	0.030	0.6	2.8	0.0058	0.1	0.5	0.04	0.9	3.7	0.004	0.1	0.4	0.0075	0.2	0.7
EP-5	Distillate Hydrotreater Charge Heater	25	0.033	0.8	3.6	0.0058	0.1	0.6	0.04	1.0	4.4	0.004	0.1	0.4	0.0075	0.2	0.8
	Distillate Hydrotreater Splitter Reboiler	117.1	0.032	3.7	16.4	0.0058	0.7	3.0	0.04	4.7	20.5	0.004	0.5	2.1	0.0075	0.9	3.8
EP-6	Hydrocracker Unit Charge Heater	69.8	0.034	2.4	10.4	0.0058	0.4	1.8	0.04	2.8	12.2	0.004	0.3	1.2	0.0075	0.5	2.3
	Hydrocracker Unit Main Fractionator Heater	211.3	0.025	5.3	23.1	0.0058	1.2	5.4	0.04	8.5	37.0	0.004	0.8	3.7	0.0075	1.6	6.9
EP-7	Hydrogen Reformer Heater	1434.9	0.0125	17.9	78.6	0.0058	8.3	36.5	0.04	57.4	251.4	0.004	5.7	25.1	0.0075	10.8	47.1
EP-10	Delayed Coking Unit Charge Heaters	198.9	0.030	6.0	26.1	0.0058	1.2	5.1	0.04	8.0	34.8	0.004	0.8	3.5	0.0075	1.5	6.5
EP-19	Butane Conversion Unit Charge Heater	310.9	0.0125	3.9	17.0	0.0058	1.8	7.9	0.04	12.4	54.5	0.004	1.2	5.4	0.0075	2.3	10.2
	Butane Conversion Unit Interstage Heater	327.5	0.0125	4.1	17.9	0.0058	1.9	8.3	0.04	13.1	57.4	0.004	1.3	5.7	0.0075	2.5	10.8
EP-20	Butane Conversion Unit Stripper Reboiler	222.0	0.0125	2.8	12.2	0.0058	1.3	5.7	0.04	8.9	38.9	0.004	0.9	3.9	0.0075	1.7	7.3
EP-23	Wastewater Treatment Plant Spray Dryer Heater	44.0	0.030	1.3	5.8	0.0058	0.3	1.1	0.04	1.8	7.7	0.004	0.2	0.8	0.0075	0.3	1.4
TOTAL				60.7	265.8		22.7	99.3		155.9	682.7		15.6	68.3		29.2	128.0

Table III-B. Process Heater Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Ammonia			Hydrogen Sulfide			Acetaldehyde			Benzene		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-1	Atm. Crude Heater	346	0.0019	0.66	2.88	2.37E-04	8.2E-02	3.6E-04	2.43E-06	8.4E-04	3.7E-03	6.24E-05	2.2E-02	9.5E-02
	Vac. Crude Heater	100	0.0019	0.19	0.84	2.37E-04	2.4E-02	1.0E-04	2.43E-06	2.4E-04	1.1E-03	6.24E-05	6.3E-03	2.8E-02
EP-2	Catalytic Reforming Unit Charge Heater	122	0.0019	0.23	1.02	2.37E-04	2.9E-02	1.3E-04	2.43E-06	3.0E-04	1.3E-03	6.24E-05	7.6E-03	3.3E-02
	Catalytic Reforming Unit Interheater #1	192	0.0019	0.37	1.60	2.37E-04	4.6E-02	2.0E-04	2.43E-06	4.7E-04	2.0E-03	6.24E-05	1.2E-02	5.3E-02
	Catalytic Reforming Unit Interheater #2	129	0.0019	0.25	1.07	2.37E-04	3.1E-02	1.3E-04	2.43E-06	3.1E-04	1.4E-03	6.24E-05	8.1E-03	3.5E-02
EP-3	Catalytic Reforming Unit Debutanizer Reboiler	23	-----	-----	-----	2.37E-04	5.5E-03	2.4E-05	2.43E-06	5.6E-05	2.5E-04	6.24E-05	1.4E-03	6.3E-03
EP-4	Naphtha Hydrotreater Charge Heater	21.4	-----	-----	-----	2.37E-04	5.1E-03	2.2E-05	2.43E-06	5.2E-05	2.3E-04	6.24E-05	1.3E-03	5.8E-03
EP-5	Distillate Hydrotreater Charge Heater	25	-----	-----	-----	2.37E-04	5.9E-03	2.6E-05	2.43E-06	6.1E-05	2.7E-04	6.24E-05	1.6E-03	6.8E-03
	Distillate Hydrotreater Splitter Reboiler	117.1	-----	-----	-----	2.37E-04	2.8E-02	1.2E-04	2.43E-06	2.8E-04	1.2E-03	6.24E-05	7.3E-03	3.2E-02
EP-6	Hydrocracker Unit Charge Heater	69.8	-----	-----	-----	2.37E-04	1.7E-02	7.2E-05	2.43E-06	1.7E-04	7.4E-04	6.24E-05	4.4E-03	1.9E-02
	Hydrocracker Unit Main Fractionator Heater	211.3	-----	-----	-----	2.37E-04	5.0E-02	2.2E-04	2.43E-06	5.1E-04	2.2E-03	6.24E-05	1.3E-02	5.8E-02
EP-7	Hydrogen Reformer Heater	1434.9	0.0019	2.73	11.94	2.37E-04	3.4E-01	1.5E-03	2.43E-06	3.5E-03	1.5E-02	6.24E-05	9.0E-02	3.9E-01
EP-10	Delayed Coking Unit Charge Heaters	198.9	-----	-----	-----	2.37E-04	4.7E-02	2.1E-04	2.43E-06	4.8E-04	2.1E-03	6.24E-05	1.2E-02	5.4E-02
EP-19	Butane Conversion Unit Charge Heater	310.9	0.0019	0.59	2.59	2.37E-04	7.4E-02	3.2E-04	2.43E-06	7.6E-04	3.3E-03	6.24E-05	1.9E-02	8.5E-02
	Butane Conversion Unit Interstage Heater	327.5	0.0019	0.62	2.73	2.37E-04	7.8E-02	3.4E-04	2.43E-06	8.0E-04	3.5E-03	6.24E-05	2.0E-02	9.0E-02
EP-20	Butane Conversion Unit Stripper Reboiler	222.0	0.0019	0.42	1.85	2.37E-04	5.3E-02	2.3E-04	2.43E-06	5.4E-04	2.4E-03	6.24E-05	1.4E-02	6.1E-02
EP-23	Wastewater Treatment Plant Spray Dryer Heater	44.0	-----	-----	-----	2.37E-04	1.0E-02	4.6E-05	2.43E-06	1.1E-04	4.7E-04	6.24E-05	2.7E-03	1.2E-02
TOTAL				6.1	26.5		9.2E-01	4.0E+00		9.5E-03	4.1E-02		2.4E-01	1.1E+00

Table III-B. Process Heater Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Benzo(a)pyrene			Chrysene			Fluoranthene			Formaldehyde		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-1	Atm. Crude Heater	346	3.37E-09	1.2E-06	5.1E-06	2.59E-09	9.0E-07	3.9E-06	3.10E-08	1.1E-05	4.7E-05	1.41E-05	4.9E-03	2.1E-02
	Vac. Crude Heater	100	3.37E-09	3.4E-07	1.5E-06	2.59E-09	2.6E-07	1.1E-06	3.10E-08	3.1E-06	1.4E-05	1.41E-05	1.4E-03	6.2E-03
EP-2	Catalytic Reforming Unit Charge Heater	122	3.37E-09	4.1E-07	1.8E-06	2.59E-09	3.2E-07	1.4E-06	3.10E-08	3.8E-06	1.7E-05	1.41E-05	1.7E-03	7.6E-03
	Catalytic Reforming Unit Interheater #1	192	3.37E-09	6.5E-07	2.8E-06	2.59E-09	5.0E-07	2.2E-06	3.10E-08	6.0E-06	2.6E-05	1.41E-05	2.7E-03	1.2E-02
	Catalytic Reforming Unit Interheater #2	129	3.37E-09	4.4E-07	1.9E-06	2.59E-09	3.3E-07	1.5E-06	3.10E-08	4.0E-06	1.8E-05	1.41E-05	1.8E-03	8.0E-03
EP-3	Catalytic Reforming Unit Debutanizer Reboiler	23	3.37E-09	7.8E-08	3.4E-07	2.59E-09	6.0E-08	2.6E-07	3.10E-08	7.2E-07	3.2E-06	1.41E-05	3.3E-04	1.4E-03
EP-4	Naphtha Hydrotreater Charge Heater	21.4	3.37E-09	7.2E-08	3.2E-07	2.59E-09	5.5E-08	2.4E-07	3.10E-08	6.6E-07	2.9E-06	1.41E-05	3.0E-04	1.3E-03
EP-5	Distillate Hydrotreater Charge Heater	25	3.37E-09	8.4E-08	3.7E-07	2.59E-09	6.5E-08	2.8E-07	3.10E-08	7.8E-07	3.4E-06	1.41E-05	3.5E-04	1.5E-03
	Distillate Hydrotreater Splitter Reboiler	117.1	3.37E-09	3.9E-07	1.7E-06	2.59E-09	3.0E-07	1.3E-06	3.10E-08	3.6E-06	1.6E-05	1.41E-05	1.7E-03	7.2E-03
EP-6	Hydrocracker Unit Charge Heater	69.8	3.37E-09	2.4E-07	1.0E-06	2.59E-09	1.8E-07	7.9E-07	3.10E-08	2.2E-06	9.5E-06	1.41E-05	9.8E-04	4.3E-03
	Hydrocracker Unit Main Fractionator Heater	211.3	3.37E-09	7.1E-07	3.1E-06	2.59E-09	5.5E-07	2.4E-06	3.10E-08	6.6E-06	2.9E-05	1.41E-05	3.0E-03	1.3E-02
EP-7	Hydrogen Reformer Heater	1434.9	3.37E-09	4.8E-06	2.1E-05	2.59E-09	3.7E-06	1.6E-05	3.10E-08	4.4E-05	1.9E-04	1.41E-05	2.0E-02	8.9E-02
EP-10	Delayed Coking Unit Charge Heaters	198.9	3.37E-09	6.7E-07	2.9E-06	2.59E-09	5.2E-07	2.3E-06	3.10E-08	6.2E-06	2.7E-05	1.41E-05	2.8E-03	1.2E-02
EP-19	Butane Conversion Unit Charge Heater	310.9	3.37E-09	1.0E-06	4.6E-06	2.59E-09	8.1E-07	3.5E-06	3.10E-08	9.6E-06	4.2E-05	1.41E-05	4.4E-03	1.9E-02
	Butane Conversion Unit Interstage Heater	327.5	3.37E-09	1.1E-06	4.8E-06	2.59E-09	8.5E-07	3.7E-06	3.10E-08	1.0E-05	4.4E-05	1.41E-05	4.6E-03	2.0E-02
EP-20	Butane Conversion Unit Stripper Reboiler	222.0	3.37E-09	7.5E-07	3.3E-06	2.59E-09	5.7E-07	2.5E-06	3.10E-08	6.9E-06	3.0E-05	1.41E-05	3.1E-03	1.4E-02
EP-23	Wastewater Treatment Plant Spray Dryer Heater	44.0	3.37E-09	1.5E-07	6.5E-07	2.59E-09	1.1E-07	5.0E-07	3.10E-08	1.4E-06	6.0E-06	1.41E-05	6.2E-04	2.7E-03
TOTAL				1.3E-05	5.8E-05		1.0E-05	4.4E-05		1.2E-04	5.3E-04		5.5E-02	2.4E-01

Table III-B. Process Heater Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Naphthalene			Phenol			Toluene		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-1	Atm. Crude Heater	346	1.94E-07	6.7E-05	2.9E-04	8.64E-07	3.0E-04	1.3E-03	8.35E-05	2.9E-02	1.3E-01
	Vac. Crude Heater	100	1.94E-07	2.0E-05	8.6E-05	8.64E-07	8.7E-05	3.8E-04	8.35E-05	8.4E-03	3.7E-02
EP-2	Catalytic Reforming Unit Charge Heater	122	1.94E-07	2.4E-05	1.0E-04	8.64E-07	1.1E-04	4.6E-04	8.35E-05	1.0E-02	4.5E-02
	Catalytic Reforming Unit Interheater #1	192	1.94E-07	3.7E-05	1.6E-04	8.64E-07	1.7E-04	7.3E-04	8.35E-05	1.6E-02	7.0E-02
	Catalytic Reforming Unit Interheater #2	129	1.94E-07	2.5E-05	1.1E-04	8.64E-07	1.1E-04	4.9E-04	8.35E-05	1.1E-02	4.7E-02
EP-3	Catalytic Reforming Unit Debutanizer Reboiler	23	1.94E-07	4.5E-06	2.0E-05	8.64E-07	2.0E-05	8.8E-05	8.35E-05	1.9E-03	8.5E-03
EP-4	Naphtha Hydrotreater Charge Heater	21.4	1.94E-07	4.2E-06	1.8E-05	8.64E-07	1.8E-05	8.1E-05	8.35E-05	1.8E-03	7.8E-03
EP-5	Distillate Hydrotreater Charge Heater	25	1.94E-07	4.9E-06	2.1E-05	8.64E-07	2.2E-05	9.5E-05	8.35E-05	2.1E-03	9.1E-03
	Distillate Hydrotreater Splitter Reboiler	117.1	1.94E-07	2.3E-05	1.0E-04	8.64E-07	1.0E-04	4.4E-04	8.35E-05	9.8E-03	4.3E-02
EP-6	Hydrocracker Unit Charge Heater	69.8	1.94E-07	1.4E-05	5.9E-05	8.64E-07	6.0E-05	2.6E-04	8.35E-05	5.8E-03	2.6E-02
	Hydrocracker Unit Main Fractionator Heater	211.3	1.94E-07	4.1E-05	1.8E-04	8.64E-07	1.8E-04	8.0E-04	8.35E-05	1.8E-02	7.7E-02
EP-7	Hydrogen Reformer Heater	1434.9	1.94E-07	2.8E-04	1.2E-03	8.64E-07	1.2E-03	5.4E-03	8.35E-05	1.2E-01	5.2E-01
EP-10	Delayed Coking Unit Charge Heaters	198.9	1.94E-07	3.9E-05	1.7E-04	8.64E-07	1.7E-04	7.5E-04	8.35E-05	1.7E-02	7.3E-02
EP-19	Butane Conversion Unit Charge Heater	310.9	1.94E-07	6.0E-05	2.6E-04	8.64E-07	2.7E-04	1.2E-03	8.35E-05	2.6E-02	1.1E-01
	Butane Conversion Unit Interstage Heater	327.5	1.94E-07	6.4E-05	2.8E-04	8.64E-07	2.8E-04	1.2E-03	8.35E-05	2.7E-02	1.2E-01
EP-20	Butane Conversion Unit Stripper Reboiler	222.0	1.94E-07	4.3E-05	1.9E-04	8.64E-07	1.9E-04	8.4E-04	8.35E-05	1.9E-02	8.1E-02
EP-23	Wastewater Treatment Plant Spray Dryer Heater	44.0	1.94E-07	8.5E-06	3.7E-05	8.64E-07	3.8E-05	1.7E-04	8.35E-05	3.7E-03	1.6E-02
TOTAL				7.6E-04	3.3E-03		3.4E-03	1.5E-02		3.3E-01	1.4E+00

C. Boilers

Emissions of all pollutants from boilers were calculated using emission factors and heat input capacity in the same manner described in Section III.B, above, for process heater emissions.

Both boilers are permitted to operate at maximum heat input capacity, without restriction, on a year-round basis. Thus, annual emissions are calculated assuming the hourly emission rate for 8,760 hours per year.

Emission factors used to calculate emissions from boilers are shown in Table III-C and were derived as follows:

- For NO_x and CO, the permitted emission limit is expressed in lb/MMBtu heat input and is used directly.
- For VOC, PM/PM₁₀, and SO₂, the emission factor represents an engineering estimate of the emission rate achievable with the control strategy representing BACT.
- For individual organic HAPs, the emission factor is taken from Section 1.4 of the U.S. EPA publication Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources (commonly known as “AP-42”).

Table III-C. Boiler Emissions

Emission Point No.	Description	Capacity (MMBtu/hr)	NO _x			SO ₂			CO			VOC			PM/PM ₁₀		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-8	Steam Boiler #1	419	0.0125	5.2	23.0	0.0006	0.3	1.1	0.016	6.7	29.4	0.004	1.7	7.3	0.0075	3.1	13.8
EP-9	Steam Boiler #2	419	0.0125	5.2	23.0	0.0006	0.3	1.1	0.016	6.7	29.4	0.004	1.7	7.3	0.0075	3.1	13.8
TOTAL				10.5	45.9		0.5	2.2		13.4	58.8		3.4	14.7		6.3	27.5

Table III-C. Boiler Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Benzene			Fluoranthene			Formaldehyde		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-8	Steam Boiler #1	419	2.10E-06	8.8E-04	3.9E-03	3.00E-09	1.3E-06	5.5E-06	7.50E-05	3.1E-02	1.4E-01
EP-9	Steam Boiler #2	419	2.10E-06	8.8E-04	3.9E-03	3.00E-09	1.3E-06	5.5E-06	7.50E-05	3.1E-02	1.4E-01
TOTAL				1.8E-03	7.7E-03		2.5E-06	1.1E-05		6.3E-02	2.8E-01

Table III-C. Boiler Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Naphthalene			Toluene		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-8	Steam Boiler #1	419	6.1E-07	2.6E-04	1.10E-03	3.4E-06	1.4E-03	6.2E-03
EP-9	Steam Boiler #2	419	6.1E-07	2.6E-04	1.10E-03	3.4E-06	1.4E-03	6.2E-03
TOTAL				5.1E-04	2.2E-03		2.9E-03	1.2E-02

D. Sulfur Recovery Plant

All emissions from the Sulfur Recovery Plant, with the exception of fugitive emissions due to equipment leaks, will be emitted from the stack of the Sulfur Recovery Plant Thermal Oxidizer. This section describes the emissions from the thermal oxidizer. Calculation of equipment leak emissions is presented in Section III.N, below.

Emissions of SO₂ and H₂S from the Sulfur Recovery Plant Thermal Oxidizer are based on the permitted hourly emission limits. The Sulfur Recovery Plant is permitted to operate at maximum heat input capacity, without restriction, on a year-round basis. Thus, annual emissions are calculated assuming the maximum hourly emission rate for 8,760 hours per year.

Emissions of all other pollutants from the Sulfur Recovery Plant Thermal Oxidizer were calculated using emission factors and heat input capacity in the same manner described in Section III.B, above, for process heater emissions.

Emission factors used to calculate emissions from the Sulfur Recovery Plant Thermal Oxidizer are shown in Table III-D and were derived as follows:

- For NO_x, the permitted emission limit is expressed in lb/MMBtu heat input and is used directly.
- The CO, VOC, and PM/PM₁₀ emission factors are those for natural gas combustion, as presented in Section 1.4 of AP-42.
- For individual organic HAPs, the emission factors for RFG combustion are taken from the CATEF database.

Table III-D. Sulfur Recovery Plant Emissions

Emission Point No.	Description	Capacity (MMBtu/hr)	SO ₂		H ₂ S		NO _x			CO			VOC			PM/PM ₁₀		
			lb/hr	ton/year	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-12	Sulfur Recovery Plant Thermal Oxidizer	100	33.6	147.2	0.089	0.39	0.06	6.0	26.3	0.084	8.4	36.8	0.0055	0.6	2.4	0.0076	0.8	3.3

Table III-D. Sulfur Recovery Plant Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Acetaldehyde			Benzene			Benzo(a)pyrene		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-12	Sulfur Recovery Plant Thermal Oxidizer	100	2.43E-06	2.4E-04	1.1E-03	6.24E-05	6.2E-03	2.7E-02	3.37E-09	3.4E-07	1.5E-06

Table III-D. Sulfur Recovery Plant Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Chrysene			Fluoranthene			Formaldehyde		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-12	Sulfur Recovery Plant Thermal Oxidizer	100	2.59E-09	2.6E-07	1.1E-06	3.10E-08	3.1E-06	1.4E-05	1.41E-05	1.4E-03	6.2E-03

Table III-D. Sulfur Recovery Plant Emissions (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Naphthalene			Phenol			Toluene		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-12	Sulfur Recovery Plant Thermal Oxidizer	100	1.94E-07	1.9E-05	8.5E-05	8.64E-07	8.6E-05	3.8E-04	8.35E-05	8.4E-03	3.7E-02

E. Group “B” Storage Tanks and Tank Farm Thermal Oxidizer

Emissions from this unit category include the emissions vented directly to the atmosphere from the Group “B” Storage Tanks, the emissions routed from the Group “B” Storage Tanks to the Tank Farm Thermal Oxidizer for partial control, and the emissions generated by the Tank Farm Thermal Oxidizer. As a result, the method of determining the maximum (i.e., worst-case) emission rate differs for individual pollutants and is dependent upon the averaging period. Emission calculations for the storage tanks and the thermal oxidizer are presented separately in Tables III-E-1 through III-E-4, and worst-case emission rates for each pollutant are presented in Table III-E-5. The following paragraphs describe the emission calculations in greater detail.

Hourly uncontrolled VOC emissions from the Group “B” Storage Tanks, both individually and collectively, are presented in Table III-E-1. These emission rates were calculated according to the methodology presented in AP-42 Section 7.1, using the tank parameters and stored liquid properties shown in Table III-E-1.

Hourly uncontrolled organic HAP emissions from the Group “B” Storage Tanks, collectively, are presented in Table III-E-2. These emission rates are calculated using the total uncontrolled VOC emission rate in conjunction with the speciation data shown in Table III-E-2. Speciation data for organic HAP’s were presented in the applicant’s permit application and represent the gasoline storage tank headspace composition data in U.S. EPA’s SPECIATE database.

Emissions from the Group “B” Storage Tanks will be routed to the Tank Farm Thermal Oxidizer for control of VOC and organic HAP emissions during normal operations. However, these emissions will be routed directly to atmosphere during outages of the thermal oxidizer, which is allowable under the proposed permit for up to 240 hours in any one-year period. Thus, for each pollutant that is emitted by the Group “B” Storage Tanks (i.e., VOC, benzene, ethylbenzene, hexane, toluene, and xylene), the worst-case hourly emission rate occurs during thermal oxidizer downtime. These emission rates are presented in Table III-E-5 and are equivalent to the uncontrolled hourly emission rates presented in Tables III-E-1 and III-E-2.

For the pollutants that are emitted by the Group “B” Storage Tanks, the worst-case annual emissions must also take into account the effect of the Tank Farm Thermal Oxidizer. This is true because the worst-case annual emissions would occur if the storage tanks emitted at the uncontrolled hourly rate for 240 hours per year, and with the thermal oxidizer operating for the remaining 8,520 hours per year. The maximum annual emissions occurring during thermal oxidizer downtime are presented in Table III-E-5 and are calculated as follows, using hexane emissions to illustrate:

$$E_{C_6H_{14}} = \left(\frac{2.7 \text{ lb}}{\text{hr}} \times \frac{240 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2,000 \text{ lbs}} \right) = 0.32 \text{ ton/yr}$$

The maximum annual emissions of pollutants that are emitted by the Group “B” Storage Tanks also includes the residual 2 percent of emissions that are routed to the thermal oxidizer, but not destroyed, during the 8,520 hours per year when the thermal oxidizer is operating. (Two percent represents the emissions not controlled, assuming a nominal 98 percent control efficiency.) These emissions are presented in Table III-E-3 and are calculated as follows, using hexane emissions to illustrate:

$$E_{C_6H_{14}} = \left(\frac{2.7 \text{ lb}}{\text{hr}} \times 2\% \times \frac{8,520 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2,000 \text{ lbs}} \right) = 0.23 \text{ ton/yr}$$

Three of the pollutants that are emitted by the Group “B” Storage Tanks (i.e., ethylbenzene, hexane, and xylene) are not generated in any appreciable quantity as a result of RFG combustion. For these pollutants, the worst-case annual emission rates are the sum of the values presented in Tables III-E-2 and III-E-3. These emission rates are presented in Table III-E-5 and are calculated as follows, using hexane emissions to illustrate:

$$E_{C_6H_{14}} = 0.32 \text{ ton/yr} + 0.23 \text{ ton/yr} = 0.55 \text{ ton/yr}$$

For the other pollutants that are emitted by the Group “B” Storage Tanks (i.e., VOC, benzene, and toluene), the worst-case annual emission rate presented in Table III-E-5 includes three values: the uncontrolled emissions during thermal oxidizer downtime; the residual 2 percent of emissions that are routed to the thermal oxidizer, but not destroyed, during periods when the thermal oxidizer is operating; and emissions generated by RFG combustion in the thermal oxidizer. The emissions due to RFG combustion are presented in Table III-E-4 and are calculated using emission factors and heat input capacity in the same manner described for process heater emissions in Section III.B, above. These emissions occur only during the 8,520 hours per year when the thermal oxidizer is operating. The emission factors for RFG combustion in the Tank Farm Thermal Oxidizer, as presented in Table III-E-4, are taken from the CATEF database.

Finally, for pollutants that are not emitted by the Group “B” Storage Tanks, the worst-case hourly and annual emission rates are due to RFG combustion in the Tank Farm Thermal Oxidizer. These emission rates are presented in Tables III-E-4 and III-E-5. The hourly emission rates reflect oxidizer operation at maximum heat input capacity, and the annual emission rates are based on continuous

operation at maximum capacity for 8,760 hours per year. These emissions are calculated using emission factors and heat input capacity in the same manner described in Section III.B, above, for process heater emissions. Emission factors used to calculate emissions from the thermal oxidizer are shown in Table III-E-4 and were derived as follows:

- For NO_x , the permitted emission limit is expressed in lb/MMBtu heat input and is used directly.
- For SO_2 , the emission factor is calculated using the permitted fuel sulfur limit of 35 ppmv, in the same manner as described above for SO_2 emissions from process heaters.
- The CO, VOC, and PM/PM₁₀ emission factors are those for natural gas combustion, as presented in Section 1.4 of AP-42.
- For individual organic HAP's, emission factors for RFG combustion are taken from the CATEF database.

Table III-E-1. Uncontrolled VOC Emissions from Group “B” Storage Tanks

Tank		Volume (gal)	Modeled Vapor Pressure (psia)	Diameter (ft)	Height (ft)	Annual Turnovers	Emissions
ID	Description						lb/hr
T-42215	Isomerization Feed Tank	1,890,000	8.92	90	48	128.9	1.80
T-42217	Reformer Feed Tank	2,835,000	1.69	110	48	103.8	0.40
T-42301	Ethanol Storage Tank	2,835,000	1.04	110	48	31.6	0.15
T-42303	Ether Storage Tank	2,835,000	8.23	110	48	46	6.78
T-42305	Alkylate Storage Tank	945,000	1.69	62	48	30	0.16
T-42306	Alkylate Storage Tank	945,000	1.69	62	48	30	0.16
T-42315	High Octane Reformate Tank	3,780,000	1.69	110	48	54.8	0.37
T-42316	High Octane Reformate Tank	3,780,000	1.69	110	48	54.8	0.37
T-42317	Low Octane Reformate Tank	3,780,000	1.69	110	48	54.8	0.37
T-42318	Low Octane Reformate Tank	3,780,000	1.69	110	48	54.8	0.37
T-42401	Gasoline Product Tank	1,890,000	8.92	90	48	39.7	1.76
T-42402	Gasoline Product Tank	1,890,000	8.92	90	48	39.7	1.76
T-42403	Gasoline Product Tank	1,890,000	8.92	90	48	9.9	1.74
T-42404	Gasoline Product Tank	1,890,000	8.92	90	48	9.9	1.74
T-42405	Gasoline Product Tank	1,890,000	8.92	90	48	79.5	1.78
T-42406	Gasoline Product Tank	1,890,000	8.92	90	48	79.5	1.78
T-42407	Gasoline Product Tank	1,890,000	8.92	90	48	79.5	1.78
T-42408	Gasoline Product Tank	1,890,000	8.92	90	48	79.5	1.78
T-42409	Gasoline Product Tank	1,890,000	8.92	90	48	39.7	1.76
T-42410	Gasoline Product Tank	1,890,000	8.92	90	48	39.7	1.76
T-42501	Jet Product Tank	2,835,000	1.69	110	48	59.9	0.37
T-42502	Jet Product Tank	2,835,000	1.69	110	48	59.9	0.37
T-42503	Jet Product Tank	2,835,000	1.69	110	48	59.9	0.37
T-42505	Diesel Product Tank	1,890,000	0.01	90	48	57.3	0.04
T-42506	Diesel Product Tank	1,890,000	0.01	90	48	57.3	0.04
T-42507	Diesel Product Tank	1,890,000	0.01	90	48	57.3	0.04
T-42101	Crude Oil Tank	7,560,000	3.74	175	48	56.2	0.94
T-42102	Crude Oil Tank	7,560,000	3.74	175	48	56.2	0.94
T-42103	Crude Oil Tank	7,560,000	3.74	175	48	56.2	0.94
T-42104	Crude Oil Tank	7,560,000	3.74	175	48	19.6	0.77
T-42105	Crude Oil Tank	7,560,000	3.74	175	48	19.6	0.77
T-42106	Crude Oil Tank	7,560,000	3.74	175	48	32	0.83
T-42107	Crude Oil Tank	7,560,000	3.74	175	48	32	0.83

Tank		Volume (gal)	Modeled Vapor Pressure (psia)	Diameter (ft)	Height (ft)	Annual Turnovers	Emissions	
ID	Description						lb/hr	
T-42201	Naphtha Hydrotreater Feed Tank	3,780,000	4.57	125	48	117.7	2.58	
T-42205	Distillate Hydrotreater Feed Tank	2,835,000	1.69	110	48	48.7	0.92	
T-42206	Distillate Hydrotreater Feed Tank	2,835,000	1.69	110	48	48.7	0.92	
T-42207	Distillate Hydrotreater Feed Tank	2,835,000	1.69	110	48	43.3	0.92	
T-42208	Distillate Hydrotreater Feed Tank	2,835,000	1.69	110	48	43.3	0.92	
T-42209	Hydrocracker Feed Tank	3,780,000	4.57	125	48	81.1	2.56	
T-42210	Hydrocracker Feed Tank	3,780,000	4.57	125	48	81.1	2.56	
T-43001	Gas Oil Flushing Oil Tank	756,000	4.57	60	40	67.3	1.94	
T-43002	Diesel Flushing Oil Tank	1,512,000	0.01	80	48	60.8	0.04	
T-43011	Straight Run Slop Oil Tank	756,000	4.57	60	40	20	1.92	
T-43012	Straight Run Slop Oil Tank	756,000	4.57	60	40	20	1.92	
T-43013	Cracked Slop Oil Tank	378,000	4.57	48	32	20	1.81	
T-43014	Cracked Slop Oil Tank	378,000	4.57	48	32	20	1.81	
T-44051	Vapor Recovery Unit Tank	378,000	8.92	48	32	4.2	0.83	
TOTAL								57.48

Table III-E-2. Uncontrolled Organic HAP Emissions from Group “B” Storage Tanks

VOC Emission Rate (lb/hr)	Benzene		Ethylbenzene		Hexane		Toluene		Xylenes (total)	
	% by weight	lb/hr	% by weight	lb/hr	% by weight	lb/hr	% by weight	lb/hr	% by weight	lb/hr
57.48	0.90	5.2E-01	0.22	1.3E-01	4.78	2.7E+00	2.11	1.2E+00	0.76	4.4E-01

Table III-E-3. Controlled Emissions from Tank Farm Thermal Oxidizer, Originating from Group “B” Storage Tanks

Emission Point No.	Description	Destruction Efficiency (%)	VOC			Benzene			Ethylbenzene		
			uncontrolled lb/hr	controlled lb/hr	controlled tons/year	uncontrolled lb/hr	controlled lb/hr	controlled tons/year	uncontrolled lb/hr	controlled lb/hr	controlled tons/year
EP-16	Tank Farm Thermal Oxidizer	98	57.48	1.15	4.90	5.2E-01	1.4E-02	4.4E-02	1.3E-01	2.6E-03	1.1E-02

Table III-E-3. Controlled Emissions from Tank Farm Thermal Oxidizer, Originating from Group “B” Storage Tanks (Continued)

Emission Point No.	Description	Destruction Efficiency (%)	Hexane			Toluene			Xylenes (total)		
			uncontrolled lb/hr	controlled lb/hr	controlled tons/year	uncontrolled lb/hr	controlled lb/hr	controlled tons/year	uncontrolled lb/hr	controlled lb/hr	controlled tons/year
EP-16	Tank Farm Thermal Oxidizer	98	2.7E+00	5.4E-02	2.3E-01	1.2E+00	2.4E-02	1.0E-01	4.4E-01	8.8E-03	3.7E-02

Table III-E-4. Emissions from Tank Farm Thermal Oxidizer, Due to RFG Combustion

Emission Point No.	Description	Capacity (MMBtu/hr)	NO _x			SO ₂			CO			VOC			PM/PM ₁₀		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-16	Tank Farm Thermal Oxidizer	56.3	0.04	2.3	9.9	0.0058	0.3	1.4	0.084	4.7	20.7	0.0055	0.31	1.32	0.0076	0.4	1.9

Table III-E-4. Emissions from Tank Farm Thermal Oxidizer, Due to RFG Combustion (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	H ₂ S			Benzene			Benzo(a)pyrene		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-16	Tank Farm Thermal Oxidizer	56.3	2.37E-04	1.3E-02	5.8E-02	6.24E-08	3.5E-06	1.5E-05	3.37E-09	1.9E-07	8.3E-07

Table III-E-4. Emissions from Tank Farm Thermal Oxidizer, Due to RFG Combustion (Continued)

Emission Point No.	Description	Capacity (MMBtu/hr)	Formaldehyde			Toluene		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-16	Tank Farm Thermal Oxidizer	56.3	1.41E-05	7.9E-04	3.5E-03	8.35E-05	4.7E-03	2.1E-02

Table III-E-5. Emissions from Group “B” Storage Tanks and Tank Farm Thermal Oxidizer

Pollutant	Averaging Period	Status of Thermal Oxidizer (“T.O.”)	Emissions from Tanks ¹		Emissions from Thermal Oxidizer ²		Total Emissions	
			Rate	Units	Rate	Units	Rate	Units
SO ₂	Hourly	T.O. operating	0.00	lb/hr	0.32	lb/hr	0.32	lb/hr
	Annual	T.O. operating continuously	0.00	tons/yr	1.38	tons/yr	1.38	tons/yr
NO _x	Hourly	T.O. operating	0.00	lb/hr	2.25	lb/hr	2.25	lb/hr
	Annual	T.O. operating continuously	0.00	tons/yr	9.86	tons/yr	9.86	tons/yr
CO	Hourly	T.O. operating	0.00	lb/hr	4.73	lb/hr	4.73	lb/hr
	Annual	T.O. operating continuously	0.00	tons/yr	20.71	tons/yr	20.71	tons/yr
PM/PM ₁₀	Hourly	T.O. operating	0.00	lb/hr	0.43	lb/hr	0.43	lb/hr
	Annual	T.O. operating continuously	0.00	tons/yr	1.87	tons/yr	1.87	tons/yr
VOC	Hourly	T.O. off-line	57.48	lb/hr	0.00	lb/hr	57.48	lb/hr
	Annual	T.O. off-line for 240 hours, operating for 8,520 hours	6.90	tons/yr	6.19	tons/yr	13.09	tons/yr
H ₂ S	Hourly	T.O. operating	0.0E+00	lb/hr	1.3E-02	lb/hr	1.3E-02	lb/hr
	Annual	T.O. operating continuously	0.0E+00	tons/yr	5.8E-02	tons/yr	5.8E-02	tons/yr
Benzene	Hourly	T.O. off-line	5.2E-01	lb/hr	0.0E+00	lb/hr	5.2E-01	lb/hr
	Annual	T.O. off-line for 240 hours, operating for 8,520 hours	6.2E-02	tons/yr	4.4E-02	tons/yr	1.1E-01	tons/yr
Benzo(a)pyrene	Hourly	T.O. operating	0.0E+00	lb/hr	1.9E-07	lb/hr	1.9E-07	lb/hr
	Annual	T.O. operating continuously	0.0E+00	tons/yr	8.3E-07	tons/yr	8.3E-07	tons/yr
Ethylbenzene	Hourly	T.O. off-line	1.3E-01	lb/hr	0.0E+00	lb/hr	1.3E-01	lb/hr
	Annual	T.O. off-line for 240 hours, operating for 8,520 hours	1.6E-02	tons/yr	1.1E-02	tons/yr	2.7E-02	tons/yr
Formaldehyde	Hourly	T.O. operating	0.0E+00	lb/hr	7.9E-04	lb/hr	7.9E-04	lb/hr
	Annual	T.O. operating continuously	0.0E+00	tons/yr	3.5E-03	tons/yr	3.5E-03	tons/yr
Hexane	Hourly	T.O. off-line	2.7E+00	lb/hr	0.0E+00	lb/hr	2.7E+00	lb/hr
	Annual	T.O. off-line for 240 hours, operating for 8,520 hours	3.2E-01	tons/yr	2.3E-01	tons/yr	5.5E-01	tons/yr
Toluene	Hourly	T.O. off-line	1.2E+00	lb/hr	0.0E+00	lb/hr	1.2E+00	lb/hr
	Annual	T.O. off-line for 240 hours, operating for 8,520 hours	1.4E-01	tons/yr	1.2E-01	tons/yr	2.5E-01	tons/yr
Xylenes (total)	Hourly	T.O. off-line	4.4E-01	lb/hr	0.0E+00	lb/hr	4.4E-01	lb/hr
	Annual	T.O. off-line for 240 hours, operating for 8,520 hours	5.3E-02	tons/yr	3.7E-02	tons/yr	9.0E-02	tons/yr

Notes:

1. Includes only emissions occurring directly to the atmosphere, i.e., during T.O. downtime. (See Tables III-E-1 and III-E-2.)
2. Includes emissions that are routed from storage tanks to the T.O. but not destroyed (see Table III-E-3) and emissions from RFG combustion (see Table III-E-4).

F. Wastewater Treatment Plant

Emission units within the WWTP at the proposed refinery will include the following:

- Four WWTP vessels, including an Oil-Water Separator, a Dissolved Air Flotation Unit, an Equalization Tank, and a Biotreater;
- The WWTP Thermal Oxidizer;
- The WWTP Spray Dryer;
- The WWTP Spray Dryer Heater; and
- Fugitive emissions due to equipment leaks.

This section describes the emissions from the WWTP vessels and the thermal oxidizer. Emissions from the WWTP Spray Dryer Heater are presented in Section III.B, above; emissions from the WWTP Spray Dryer are presented in Section III.K, below; and equipment leak emissions are presented in Section III.N, below.

All emissions from the WWTP vessels will be routed to the WWTP Thermal Oxidizer. Emissions from the thermal oxidizer include both the emissions routed from the WWTP vessels to the thermal oxidizer for partial control, and the emissions generated by the thermal oxidizer. As a result, the method of calculating the emission rate differs for individual pollutants. Emission rates for pollutants generated by the WWTP vessels and the thermal oxidizer are presented separately in Tables III-F-1 and III-F-2, and combined emission rates for each pollutant are presented in Table III-F-3. The following paragraphs describe the emission calculations in greater detail.

Hourly and annual uncontrolled and controlled VOC and benzene emissions from the collection of WWTP vessels are presented in Table III-F-1. These emission rates were calculated based on the conservative assumption that all VOC and benzene removed in the WWTP are routed to the WWTP Thermal Oxidizer as gaseous emissions. Values used in the calculations include a design maximum wastewater capacity of 1,000 gallons per minute; an assumed wastewater density of 8.4 lb/gal; design maximum wastewater VOC and benzene concentrations of 800 ppmw and 40 ppmw, respectively; and a 98 percent destruction efficiency for VOC and benzene emissions routed to the WWTP Thermal Oxidizer, which represents a conservative estimate of the emission reduction achievable when using the control technology representing BACT. The calculation methodology, using hourly VOC emissions to illustrate, is as follows:

$$E_{\text{VOC(unc.)}} = \frac{1,000 \text{ gal WW}}{\text{min}} \times \frac{8.4 \text{ lb WW}}{\text{gal WW}} \times \frac{60 \text{ min}}{\text{hr}} \times \frac{800 \text{ lb VOC}}{10^6 \text{ lb WW}} = 403.2 \text{ lb/hr}$$

Hourly and annual emission rates due to RFG combustion in the WWTP Thermal Oxidizer are presented in Table III-F-2. The hourly emission rates reflect oxidizer operation at maximum heat input capacity, and the annual emission rates are based on continuous operation at maximum capacity for 8,760 hours per year. These emissions are calculated using emission factors and heat input capacity, in the same manner described for process heater emissions in Section III.B herein. Emission factors used to calculate emissions from the WWTP Thermal Oxidizer are shown in Table III-F-4 and were derived as follows:

- For SO₂, the emission factor is calculated using the permitted fuel sulfur limit of 35 ppmv, in the same manner as described in Section III.B, above, for SO₂ emissions from process heaters.
- The NO_x, CO, VOC, and PM/PM₁₀ emission factors are those for natural gas combustion, as presented in Section 1.4 of AP-42.

Table III-F-1. Emissions from WWTP Thermal Oxidizer, Originating from WWTP Vessels

Emission Point No.	Description	Destruction Efficiency (%)	VOC			Benzene		
			uncontrolled lb/hr	controlled lb/hr	controlled tons/year	uncontrolled lb/hr	controlled lb/hr	controlled tons/year
EP-18	WWTP Thermal Oxidizer	98	403.2	8.06	35.32	20.16	0.40	1.77

Table III-F-2. Emissions from WWTP Thermal Oxidizer, Due to RFG Combustion

Emission Point No.	Description	Capacity (MMBtu/hr)	NO _x			SO ₂			CO			VOC			PM/PM ₁₀		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-18	WWTP Thermal Oxidizer	0.334	0.10	0.033	0.146	0.0058	0.002	0.008	0.084	0.028	0.123	0.0055	0.002	0.008	0.0076	0.003	0.011

Table III-F-3. Emissions from WWTP Thermal Oxidizer, Total

Emission Point No.	Description	NO _x		SO ₂		CO		VOC		Benzene		PM/PM ₁₀	
		lb/hr	ton/year	lb/hr	ton/year	lb/hr	ton/year	lb/hr	ton/year	lb/hr	ton/year	lb/hr	ton/year
EP-18	WWTP Thermal Oxidizer	0.033	0.146	0.002	0.008	0.028	0.123	8.06	35.33	0.40	1.77	0.003	0.011

G. Truck and Rail Car Loading Racks

All emissions from the loading of gasoline and distillate products into trucks and rail cars, with the exception of fugitive emissions due to equipment leaks, will be emitted from the stacks of the loading rack thermal oxidizers. Specifically, emissions from the Gasoline Product Rail Car Loading Racks and the Distillate Product Rail Car Loading Racks will be routed to the Rail Car Loading Rack Thermal Oxidizer and emissions from the Gasoline Product Truck Loading Racks and the Distillate Product Truck Loading Racks will be routed to the Truck Loading Rack Thermal Oxidizer. This section describes the emissions from the thermal oxidizers. Calculation of equipment leak emissions is presented in Section III.N, below.

Emissions from the loading racks include both the emissions routed from the loading racks to the loading rack thermal oxidizers for partial control, and the emissions generated by the thermal oxidizers. As a result, the method of calculating the emission rate differs for individual pollutants. Emission rates for VOC, which is generated by the loading operations and partially controlled in the thermal oxidizers, are presented in Table III-G-1. (Emissions of VOC from gasoline product loading operations will also be partially controlled using regenerative adsorption systems upstream of the thermal oxidizers but, as described below, this does not affect the manner in which VOC emissions are calculated.) Emission rates for pollutants that are generated by combustion of RFG in the thermal oxidizers are presented in Table III-G-2. The following paragraphs describe the emission calculations in greater detail.

Hourly and annual VOC emissions from the loading rack thermal oxidizers are presented in Table III-G-1. These emission rates are based on the permitted emission limits and the design maximum loading rates. Specifically, the emission limits in the proposed permit are expressed in terms of pounds per million gallons of product, with separate factors for loading of gasoline products and distillate products. The method for determining the composite emission limit for a particular thermal oxidizer is presented in the proposed permit and is as follows:

a. VOC Emission Standards

The Permittee shall not cause or allow to be emitted to the atmosphere from the Loading Rack Thermal Oxidizer or the Rail Car Loading Rack Thermal Oxidizer any gases which contain VOC in excess of the following amounts:

(1) *1.25 pounds per million gallons of product loaded at the gasoline product loading racks.*

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(2) *22.0 pounds per million gallons of product loaded at the distillate product loading racks.*

- (3) For periods when a loading rack thermal oxidizer is receiving vapors displaced from both gasoline product loading racks and distillate product loading racks, an amount (E_{total}) determined as follows:

$$E_{total} = EL_g V_g + EL_d V_d$$

Where:

E_{total} = VOC emission limit, pounds

EL_g = VOC emission limit for gasoline product loading racks, 1.25 pounds per million gallons loaded

V_g = Volume of product loaded at the gasoline loading product racks, millions of gallons

EL_d = VOC emission limit for distillate product loading racks, 22.0 pounds per million gallons loaded

V_d = Volume of product loaded at the gasoline loading product racks, millions of gallons

Loading rack throughput values used in the VOC emission calculations are presented in Table III-G-1 and were derived as follows:

- The hourly gasoline product throughput value of 1.62 million gallons for each set of loading racks (i.e., the collection of all loading racks served by one thermal oxidizer) is based on a pumping capacity of 600 gallons per minute per loading arm and a total of 45 gasoline product loading arms in each set.
- The hourly distillate product throughput value of 540,000 gallons for each set of loading racks is based on a pumping capacity of 600 gallons per minute per loading arm and a total of 9 distillate product loading arms in each set.
- The annual gasoline product throughput value of 469.5 million gallons for each set of loading racks represents half of the design maximum annual production rate for gasoline products at the proposed refinery, as indicated by the applicant in the permit application.

- The annual distillate product throughput value of 555.5 million gallons for each set of loading racks represents half of the design maximum annual production rate for distillate products at the proposed refinery, as indicated by the applicant in the permit application.

The calculation methodology for VOC emissions, using hourly VOC emissions from the Truck Loading Rack Thermal Oxidizer to illustrate, is as follows:

$$E_{\text{voc}} = \left(\frac{1.62 \text{ MMgal gasoline}}{\text{hour}} \times \frac{1.25 \text{ lb VOC}}{\text{MMgal gasoline}} \right) + \left(\frac{0.54 \text{ MMgal distillate}}{\text{hour}} \times \frac{22.0 \text{ lb VOC}}{\text{MMgal distillate}} \right) = 13.91 \text{ lb/hr}$$

Hourly and annual emission rates due to RFG combustion in the loading rack thermal oxidizers are presented in Table III-G-2. The hourly emission rates reflect oxidizer operation at maximum heat input capacity, and the annual emission rates are based on continuous operation at maximum capacity for 8,760 hours per year. These emissions are calculated using emission factors and heat input capacity in the same manner described for process heater emissions in Section III.B, above. Emission factors used to calculate emissions from the loading rack thermal oxidizers are shown in Table III-G-2 and were derived as follows:

- For SO₂, the emission factor is calculated using the permitted fuel sulfur limit of 35 ppmv, in the same manner as described above for SO₂ emissions from process heaters.
- The NO_x, CO, and PM/PM₁₀ emission factors are those for natural gas combustion, as presented in Section 1.4 of AP-42.

Table III-G-1. VOC Emissions from Loading Rack Thermal Oxidizers

Emission Point No.	Description	Averaging Period	Gasoline Product Loading Rack			Distillate Product Loading Rack			VOC Emissions from all Loading Racks (lb/hr or ton/yr)
			Throughput (MMgal)	Emission Limit (lb/MMgal)	Emission Rate (lb/hr or ton/yr)	Throughput (MMgal)	Emission Limit (lb/MMgal)	Emission Rate (lb/hr or ton/yr)	
EP-17	Truck Loading Rack Thermal Oxidizer								
		Hourly	1.62	1.25	2.03	0.54	22.0	11.88	13.91
		Annual	469.5	1.25	0.29	555.5	22.0	6.11	6.40
EP-27	Rail Car Loading Rack Thermal Oxidizer								
		Hourly	1.62	1.25	2.03	0.54	22.0	11.88	13.91
		Annual	469.5	1.25	0.29	555.5	22.0	6.11	6.40
Total for Both Loading Rack Thermal Oxidizers									
		Hourly	3.24	1.25	4.05	1.08	22.0	23.76	27.81
		Annual	939	1.25	0.59	1,111	22.0	12.22	12.81

Table III-G-2. Emissions from Loading Rack Thermal Oxidizers, Due to RFG Combustion

Emission Point No.	Description	Capacity (MMBtu/hr)	NO _x			SO ₂			CO			PM/PM ₁₀		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-17	Truck Loading Rack Thermal Oxidizer	12.33	0.10	1.23	5.40	0.0058	0.07	0.31	0.084	1.04	4.54	0.0076	0.09	0.41
EP-27	Rail Car Loading Rack Thermal Oxidizer	12.33	0.10	1.23	5.40	0.0058	0.07	0.31	0.084	1.04	4.54	0.0076	0.09	0.41
TOTAL				2.47	10.80		0.14	0.62		2.07	9.07		0.19	0.82

H. Sour Water Tank

The Sour Water Tank will be a source of H₂S emissions due to the presence of H₂S in the liquid stored in this tank. The H₂S emission rates from the internal floating roof storage tank, prior to the application of the carbon adsorption system, were calculated according to the methodology presented in AP-42 Section 7.1, using the tank parameters and stored liquid properties shown in Table III-H-1.

The maximum actual hourly and annual H₂S emissions from the Sour Water Tank are calculated using a conservatively assumed 95 percent control efficiency, reflecting the minimum design control efficiency, for the carbon adsorption system. (Five percent represents the emissions not controlled, assuming a nominal 95 percent control efficiency.) These emissions also are presented in Table III-I-1 and are calculated as follows:

$$E_{\text{H}_2\text{S}} = \left(\frac{11 \text{ lb}}{\text{yr}} \times 5\% \right) = 0.55 \text{ lb/yr}$$

Table III-H-1. H₂S Emissions from Sour Water Tank

Tank		Volume (gal)	Diameter (ft)	Height (ft)	Annual Turnovers	H ₂ S Liquid Concentration (ppmw)	Modeled H ₂ S Vapor Pressure (psia)	Uncontrolled H ₂ S Emissions		Control Efficiency (%)	Controlled H ₂ S Emissions	
ID	Description							lb/hr	lb/yr		lb/hr	lb/yr
T-11100	Sour Water Tank	3,780,000	110	48	365	4,000	0.00011	0.001	11	95	0.0001	0.55

I. Emergency Flares

Emissions of all pollutants from the emergency flares were calculated using emission factors and heat input rates (from pilot gas and purge gas) in the same manner described in Section III.B, above, for process heater emissions.

Emission factors and heat input rates used to calculate emissions from the emergency flares are shown in Table III-I. Both emergency flares are expected to operate continuously on a year-round basis. Thus, annual emissions are calculated assuming the hourly emission rate for 8,760 hours per year.

Emission factors used to calculate emissions from the emergency flares were derived from Section 13.5 of AP-42.

Table III-I. Emergency Flare Emissions

Emission Point No.	Description	Heat Input Rate (MMBtu/hr)	NO _x			SO ₂			CO			VOC		
			lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year	lb/MMBtu	lb/hr	ton/year
EP-13	Emergency Flare #1	0.83	0.068	0.06	0.25	0.0006	5.3E-04	2.3E-03	0.37	0.31	1.35	0.063	0.05	0.23
EP-21	Emergency Flare #2	0.83	0.068	0.06	0.25	0.0006	5.3E-04	2.3E-03	0.37	0.31	1.35	0.063	0.05	0.23
TOTAL				0.11	0.50		1.1E-03	4.6E-03		0.62	2.70		0.10	0.46

J. Coke Silo Baghouse

Exhaust gases from the Coke Silo will be routed to the Coke Silo Baghouse for control of particulate matter emissions.

Hourly particulate matter emissions from the Coke Silo Baghouse were calculated as the product of the permitted maximum exhaust gas particulate matter concentration (i.e., “grain loading”) and the design maximum exhaust gas flow rate. This calculation is as follows:

$$E_{PM} = \frac{\left(2,188 \frac{\text{dscf}}{\text{min}}\right) \times \left(0.005 \frac{\text{gr}}{\text{dscf}}\right) \times \left(60 \frac{\text{min}}{\text{hr}}\right)}{\left(7,000 \frac{\text{gr}}{\text{lb}}\right)} = 0.09 \text{ lb/hr}$$

The Coke Silo is permitted to operate at maximum capacity, without restriction, on a year-round basis. Thus, annual emissions from the Coke Silo Baghouse are calculated assuming the hourly emission rate for 8,760 hours per year, as follows:

$$E_{PM} = \frac{\left(0.09 \frac{\text{lb}}{\text{hr}}\right) \times \left(8,760 \frac{\text{hr}}{\text{yr}}\right)}{\left(2,000 \frac{\text{lb}}{\text{ton}}\right)} = 0.41 \text{ ton/yr}$$

K. Spray Dryer Baghouse

Exhaust gases from the WWTP Spray Dryer will be routed to the Spray Dryer Baghouse for control of particulate matter emissions.

Hourly particulate matter emissions from the Spray Dryer Baghouse were calculated as the product of the permitted maximum exhaust gas particulate matter concentration (i.e., “grain loading”) and the design maximum exhaust gas flow rate. This calculation is as follows:

$$E_{PM} = \frac{\left(27,228 \frac{\text{dscf}}{\text{min}}\right) \times \left(0.005 \frac{\text{gr}}{\text{dscf}}\right) \times \left(60 \frac{\text{min}}{\text{hr}}\right)}{\left(7,000 \frac{\text{gr}}{\text{lb}}\right)} = 1.17 \text{ lb/hr}$$

The WWTP Spray Dryer is permitted to operate at maximum capacity, without restriction, on a year-round basis. Thus, annual emissions from the Spray Dryer Baghouse are calculated assuming the hourly emission rate for 8,760 hours per year, as follows:

$$E_{PM} = \frac{\left(1.17 \frac{\text{lb}}{\text{hr}}\right) \times \left(8,760 \frac{\text{hr}}{\text{yr}}\right)}{\left(2,000 \frac{\text{lb}}{\text{ton}}\right)} = 5.11 \text{ ton/yr}$$

L. Catalyst Regenerators

There are two catalyst regenerators at the proposed refinery, one at the Catalytic Reforming Unit and one at the Butane Conversion Unit. Hourly and annual emissions from these catalyst regenerators are presented in Table III-L.

The applicant has indicated that the catalyst regenerators are similar to one another and, as shown in Table III-L, the estimated emission rates for both catalyst regenerators are identical. The pollutants emitted by each catalyst regenerator include CO, NO_x, perchloroethylene, hydrogen chloride, and chlorine. Two different emission calculation methodologies are needed to calculate the emission rates. These methodologies are described in more detail in the following paragraphs.

Emissions of CO, NO_x, perchloroethylene, and hydrogen chloride are based on design maximum exhaust gas flow rates and pollutant concentrations. The exhaust gas CO and NO_x concentrations for both catalyst regenerators are based on information provided by the applicant in the permit application. The Catalytic Reforming Unit Catalyst Regenerator exhaust gas perchloroethylene and hydrogen chloride concentrations of 20 ppmv and 10 ppmv, respectively, are based on the permitted maximum concentrations. The perchloroethylene and hydrogen chloride concentrations in the Butane Conversion Unit Catalyst Regenerator exhaust, while not subject to the same emission limits, were assumed by the Department to be the same due to the similarities between this unit and the Catalytic Reforming Unit Catalyst Regenerator.

A material balance was used to estimate hourly and annual emissions of chlorine. These material balance calculations were performed by the applicant, and only the resulting emission rates (as shown in Table III-L) were presented in the permit application. Emissions of chlorine from the catalyst regenerators are not subject to any applicable regulations, and the Department is not aware of any published emission data for this type of emission unit. The Department performed engineering calculations and determined that the chlorine emission rates presented by the applicant represent an exhaust gas concentration of approximately 10 ppmv. The Department judges this to be a conservative estimate of the level that is achievable, considering that each of the catalyst regenerators will be equipped with a caustic scrubber.

The exhaust gas flow rates and pollutant concentrations used in calculating hourly CO, NO_x, hydrogen chloride, and perchloroethylene emission rates from the catalyst regenerators are presented in Table III-L. Both catalyst regenerators are permitted to operate at maximum capacity, without restriction, on a year-round basis. Thus, annual emissions are calculated assuming the hourly emission rate for 8,760 hours per year. Other values required for the emission rate calculations are a physical constant of 385.55 standard cubic feet per pound-mole of gas and the molecular weight of each pollutant. These molecular weights are as follows:

28 pounds per pound-mole for CO; 46 pounds per pound-mole for NO_x; 36.5 pounds per pound-mole for hydrogen chloride; and 166 pounds per pound-mole for perchloroethylene. The calculation of an hourly emission rate, using the CO emission rate to illustrate, is as follows:

$$E_{CO} = \frac{\left(\frac{200 \text{ lb} \cdot \text{mol CO}}{10^6 \text{ lb} \cdot \text{mol exhaust}} \right) \times \left(\frac{28 \text{ lb CO}}{\text{lb} \cdot \text{mol CO}} \right)}{\left(\frac{385.55 \text{ scf exhaust}}{\text{lb} \cdot \text{mol exhaust}} \right)} \times \left(575 \frac{\text{scf exhaust}}{\text{min}} \right) \times \left(60 \frac{\text{min}}{\text{hr}} \right) = 0.50 \text{ lb/hr}$$

Table III-L. Catalyst Regenerator Emissions

Emission Point No.	Description	Exhaust Flow Rate (scfm)	Chlorine		Hydrogen Chloride		Perchloroethylene			CO			NO _x			
			lb/hr	ton/year	ppmv	lb/hr	ton/year	ppmv	lb/hr	ton/year	ppmv	lb/hr	ton/year	ppmv	lb/hr	ton/year
EP-11	Catalytic Reforming Unit Catalyst Regenerator	575	0.06	0.26	10	0.033	0.14	20	0.30	1.30	200	0.50	2.20	200	0.82	3.61
EP-22	Butane Conversion Unit Catalyst Regenerator	575	0.06	0.26	10	0.033	0.14	20	0.30	1.30	200	0.50	2.20	200	0.82	3.61
TOTAL			0.12	0.52		0.065	0.29		0.60	2.60		1.00	4.40		1.65	7.22

M. Cooling Tower

Emissions from the cooling tower include particulate matter, VOC, and benzene. Particulate matter emissions occur due to liquid drift from the tower. Emissions of VOC and benzene could occur due to evaporation from the tower if leaking heat exchangers within refinery process units caused these pollutants to be captured within the cooling water system. Hourly and annual emissions from the cooling tower are presented in Table III-M, and the methods used to determine these emission rates are described in the following paragraphs.

Emissions of VOC from the cooling tower were calculated as the product of the permitted maximum cooling water flow rate of 80,000 gallons per minute and an emission factor of 0.7 pounds per million gallons of cooling water flow. This emission factor is derived from Section 5.1 of AP-42. The hourly VOC emission rate calculation is as follows:

$$E_{\text{VOC}} = \left(80,000 \frac{\text{gal}}{\text{min}} \right) \times \left(60 \frac{\text{min}}{\text{hr}} \right) \times \left(\frac{0.7 \text{ lb}}{10^6 \text{ gal}} \right) = 3.36 \text{ lb/hr}$$

Hourly particulate matter emissions from the cooling tower, as shown in Table III-M, are based on the PM emission limit of 1.6 lb/hr included in the proposed permit. This value was calculated using the maximum cooling water flow rate of 80,000 gallons per minute, a water density of 8.3 pounds per gallon, a total suspended solids (TSS) concentration of 8,000 ppmw, and a drift rate of 0.0005 percent. This calculation is as follows:

$$E_{\text{PM}} = \left(80,000 \frac{\text{gal}}{\text{min}} \right) \times \left(8.3 \frac{\text{lb H}_2\text{O}}{\text{gal}} \right) \times \left(60 \frac{\text{min}}{\text{hr}} \right) \times \left(\frac{0.008 \text{ lb TSS}}{\text{lb H}_2\text{O}} \right) \times \left(\frac{0.000005 \text{ lb PM}}{\text{lb TSS}} \right) = 1.6 \text{ lb/hr}$$

The Cooling Tower is permitted to operate at maximum capacity, without restriction, on a year-round basis. Thus, annual emissions from the Cooling Tower are calculated assuming the hourly emission rate for 8,760 hours per year. This calculation is as follows, using annual particulate matter emissions to illustrate:

$$E_{\text{PM}} = \frac{\left(1.6 \frac{\text{lb}}{\text{hr}} \right) \times \left(8,760 \frac{\text{hr}}{\text{yr}} \right)}{\left(2,000 \frac{\text{lb}}{\text{ton}} \right)} = 7.01 \text{ ton/yr}$$

Hourly and annual emissions of benzene from the cooling tower were calculated using the corresponding VOC emission rate in conjunction with an assumed benzene concentration of 1.21 percent by weight in the VOC contained in cooling water. The benzene concentration value represents a conservative estimate of the benzene concentration of typical light liquid streams within the proposed refinery and were derived from Table 6-6 of the U.S. EPA publication "Locating and Estimating Air Emissions from Sources of Benzene" (EPA-454/R-98-011), June 1998. The calculation of benzene emissions, using the hourly benzene emission

rate, is as follows:

$$E_{C_6H_6} = \left(3.36 \frac{\text{lb VOC}}{\text{hr}} \right) \times \left(0.0121 \frac{\text{lb } C_6H_6}{\text{lb VOC}} \right) = 0.041 \text{ lb/hr}$$

Table III-M. Cooling Tower Emissions

Emission Point No.	Description	Cooling Water Flow Rate (gal/min)	PM		VOC			Benzene		
			lb/hr	ton/year	lb/MMgal	lb/hr	ton/year	% by weight in VOC	lb/hr	ton/year
EP-V1	Cooling Tower	80,000	1.6	7.01	0.7	3.36	14.7	1.21	0.04	0.18

N. Equipment Leaks

Fugitive emissions of VOC, organic HAPs, and H₂S will occur due to leaking piping components and other equipment (e.g., screwed and flanged connectors, valves, pumps, and compressors) at the proposed refinery. Emissions from equipment leaks are summarized in Table III-N-1.

Table III-N-1. Emissions from Equipment Leaks

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
VOC	16.8	13.2
H ₂ S	0.27	1.22
Benzene	0.14	0.11
Ethylbenzene	0.04	0.03
Hexane	0.80	0.63
Toluene	0.35	0.28
Xylenes (total)	0.13	0.10

All emissions from equipment leaks were calculated using the “EPA Correlation Approach” set forth in the U.S. EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), November 1995. This approach uses exponential equations based on the results of extensive studies quantifying and correlating petroleum refinery component leak concentrations and mass emission rates. These equations are designed to predict the mass emission rate from a component based on the VOC concentration, as measured by U.S. EPA Reference Method 21, at the leak interface. (All subsequent references to concentration within this section refer to the pollutant concentration on this basis.) In addition to the exponential equations, the EPA Correlation Approach includes emission rates for components with zero VOC concentration at the leak interface. These “default zero” emission rates are small, but are larger than would be predicted by the correlation equations, and are based on study data showing non-zero mass emission rates from components with VOC concentration below the method detection limit. The correlation equations and default zero emission rates are presented in Table III-N-2.

Table III-N-2. Petroleum Refinery Equipment Leak Correlation Equations

Equipment type	Correlation Equation (kg/hr/component)	Default Zero (kg/hr/component)
Valves	$2.29\text{E-}06 \times (C_{\text{VOC}})^{0.746}$	7.8E-06
Pump seals	$5.03\text{E-}05 \times (C_{\text{VOC}})^{0.610}$	2.4E-05
Compressor seals	$2.20\text{E-}06 \times (C_{\text{VOC}})^{0.704}$	4.0E-06
Flanges	$4.61\text{E-}06 \times (C_{\text{VOC}})^{0.703}$	3.1E-07

The proposed permit defines a leaking component, or “leaker,” as a component that emits VOC at such a rate that the concentration, as measured by U.S. EPA Reference Method 21, exceeds a specified level. For valves and connectors in gas/vapor service and light liquid service, the concentration is 100 ppmv; for all other component types, the concentration is 500 ppmv or greater. Estimates of maximum hourly emissions of VOC from equipment leaks were based on the conservative assumption that 2 percent of all components in VOC service (e.g., pumps and valves) are leakers and 98 percent are non-leakers. Each leaker was conservatively assumed to be emitting at an equivalent concentration of 10,000 ppmv. Forty-eight percent of the components (i.e., roughly half of the non-leakers) were conservatively assumed to be emitting at an equivalent concentration equal to that at which they would be considered leakers. The remaining 50 percent of the components were assumed to be emitting at the default zero emission rate. Hourly VOC emission rates for each process unit at the proposed refinery, along with the component counts and emission factors used to calculate them, are presented in Table III-N-3. The component counts are presented separately, as provided by the applicant, for equipment in gas/vapor (“VAP”) service, light hydrocarbon liquid (“LHC”) service, and heavy hydrocarbon liquid (“HHC”) service. The calculation procedure is as follows, using hourly VOC emissions from valves in gas/vapor service in the Atmospheric Distillation section of the Crude Unit (Unit 1) to illustrate:

$$E_0 = (427 \text{ valves} \times 50\%) \times \left(\left(\frac{7.8}{10^6} \right) \frac{\text{kg VOC}}{\text{hr} \cdot \text{valve}} \right) \times \left(\frac{2.2 \text{ lb VOC}}{\text{kg VOC}} \right) = 0.00367 \frac{\text{lb VOC}}{\text{hr}}$$

$$E_{100} = (427 \text{ valves} \times 48\%) \times \left(\left(\frac{2.29}{10^6} \times 100^{0.746} \right) \frac{\text{kg VOC}}{\text{hr} \cdot \text{valve}} \right) \times \left(\frac{2.2 \text{ lb VOC}}{\text{kg VOC}} \right) = 0.0321 \frac{\text{lb VOC}}{\text{hr}}$$

$$E_{10,000} = (427 \text{ valves} \times 2\%) \times \left(\left(\frac{2.29}{10^6} \times 10,000^{0.746} \right) \frac{\text{kg VOC}}{\text{hr} \cdot \text{valve}} \right) \times \left(\frac{2.2 \text{ lb VOC}}{\text{kg VOC}} \right) = 0.0415 \frac{\text{lb VOC}}{\text{hr}}$$

$$E_{\text{VOC}} = E_0 + E_{100} + E_{10,000} = 0.00367 + 0.0321 + 0.0415 = 0.0773 \frac{\text{lb VOC}}{\text{hr}}$$

Annual VOC emissions from equipment leaks were calculated in the same manner as hourly VOC emissions, with different and less conservative assumptions regarding the percentage of leakers. Specifically, annual emissions of VOC from equipment leaks were based on the conservative assumption that 0.3 percent of valves and connectors in gas/vapor service and light liquid service are leakers, reflecting an enforceable limit in the proposed permit, and 99.7 percent are non-leakers. For all other component types, 1 percent are assumed to be leakers and 99 percent non-leakers. Each leaking component, regardless of type and service, was conservatively assumed to be emitting at an equivalent concentration of 10,000 ppmv (i.e., 20 to 100 times the leak definition level). Ninety-nine percent of compressors, 49.5 percent of pumps in light hydrocarbon service, and one percent of all other component types were conservatively assumed to be emitting at an equivalent concentration equal to that at which they would be considered leakers. All remaining components were assumed to be emitting at the default zero emission rate. Annual VOC emission rates for each process unit at the proposed refinery, along with the component counts and emission factors used to calculate them, are presented in Table III-N-4. The component counts are presented separately, as provided by the applicant, for equipment in gas/vapor (“VAP”) service, light hydrocarbon liquid (“LHC”) service, and heavy hydrocarbon liquid (“HHC”) service.

Hourly and annual H₂S emissions from equipment leaks were calculated in the same manner as VOC emissions, but again with slightly different assumptions regarding the percentage of leakers and the H₂S concentration at leakers. Specifically, both hourly and annual emissions of H₂S from equipment leaks were based on the conservative assumption that 0.5 percent of all components in H₂S service are leakers, and 99.5 percent are non-leakers. The number of assumed leakers in H₂S service is smaller than the number of assumed leakers in VOC service because H₂S is both extremely toxic and easily detectable through olfactory senses, thus, leaking equipment in H₂S service will be more readily detected. For both hourly and annual H₂S emission calculations, 49.5 percent of the components (i.e., roughly half of the non-leakers) were conservatively assumed to be emitting at an equivalent concentration of 500 ppmv, and another 50 percent of components (i.e., the remaining non-leakers) were assumed to be emitting at the default zero emission rate. For the purpose of calculating hourly

emissions, each leaker was assumed to be emitting at an equivalent concentration of 5,000 ppmv, while for annual emissions, each leaker was assumed to be emitting at an equivalent concentration of 2,500 ppmv. The assumed equivalent concentrations for leakers in H₂S service are lower than the corresponding concentrations for leakers in VOC service because equipment in H₂S service will contain process fluids that contain H₂S in concentrations substantially less than 100 percent, whereas most equipment in VOC service will contain fluids that are nearly 100 percent VOC. Hourly and annual H₂S emission rates, along with the component counts and emission factors used to calculate them, are presented in Tables III-N-5 and III-N-6, respectively.

Hourly and annual benzene emissions from equipment leaks were calculated by applying process unit-specific benzene concentration data to the hourly and annual VOC emission rates presented in Tables III-N-3 and III-N-4, respectively. The benzene concentration data were derived from Tables 6-6 and 6-7 of the U.S. EPA publication "Locating and Estimating Air Emissions from Sources of Benzene" (EPA-454/R-98-011), June 1998. Hourly and annual benzene emission rates, and the process unit-specific benzene concentration values used to calculate them, are presented in Table III-N-7.

Hourly and annual emissions of other organic HAPs from equipment leaks were calculated by applying generalized petroleum refinery speciation data to the hourly and annual VOC emission rates presented in Tables III-N-3 and III-N-4, respectively. The speciation data for other organic HAP's were presented in the applicant's permit application and represent the gasoline storage tank headspace composition data in U.S. EPA's SPECIATE database. Hourly and annual emission rates for other organic HAPs, and the speciation data used to calculate them, are presented in Table III-N-8.

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 1 - Atmospheric Distillation												
Valves	VAP	427	213	1.72E-05	3.67E-03	205	1.57E-04	3.21E-02	9	4.87E-03	4.15E-02	
	LHC	1182	591	1.72E-05	1.02E-02	567	1.57E-04	8.89E-02	24	4.87E-03	1.15E-01	
	HHC	1280	640	1.72E-05	1.10E-02	614	5.21E-04	3.20E-01	26	4.87E-03	1.25E-01	
Flanges	VAP	288	144	6.83E-07	9.83E-05	138	2.59E-04	3.58E-02	6	6.59E-03	3.79E-02	
	LHC	797	398	6.83E-07	2.72E-04	383	2.59E-04	9.90E-02	16	6.59E-03	1.05E-01	
	HHC	863	432	6.83E-07	2.95E-04	414	8.02E-04	3.33E-01	17	6.59E-03	1.14E-01	
Pumps	LHC	9	5	5.29E-05	2.40E-04	4	4.91E-03	2.14E-02	0	3.05E-02	5.54E-03	
	HHC	10	5	5.29E-05	2.60E-04	5	4.91E-03	2.32E-02	0	3.05E-02	6.00E-03	
Compressors	VAP	1	1	8.82E-06	4.41E-06	0	3.85E-04	1.85E-04	0	3.18E-03	6.35E-05	
Subtotal					2.60E-02			9.53E-01			5.50E-01	1.53E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 2 - Vacuum Distillation												
Valves	VAP	113	56	1.72E-05	9.70E-04	54	1.57E-04	8.49E-03	2	4.87E-03	1.10E-02	
	LHC	88	44	1.72E-05	7.59E-04	42	1.57E-04	6.64E-03	2	4.87E-03	8.59E-03	
	HHC	585	293	1.72E-05	5.03E-03	281	5.21E-04	1.46E-01	12	4.87E-03	5.70E-02	
Flanges	VAP	80	40	6.83E-07	2.72E-05	38	2.59E-04	9.89E-03	2	6.59E-03	1.05E-02	
	LHC	62	31	6.83E-07	2.13E-05	30	2.59E-04	7.74E-03	1	6.59E-03	8.21E-03	
	HHC	413	207	6.83E-07	1.41E-04	198	8.02E-04	1.59E-01	8	6.59E-03	5.45E-02	
Pumps	LHC	1	0	5.29E-05	1.92E-05	0	4.91E-03	1.71E-03	0	3.05E-02	4.44E-04	
	HHC	5	2	5.29E-05	1.27E-04	2	4.91E-03	1.14E-02	0	3.05E-02	2.94E-03	
Compressors	VAP	2	1	8.82E-06	8.82E-06	1	3.85E-04	3.70E-04	0	3.18E-03	1.27E-04	
Subtotal					7.11E-03			3.52E-01			1.53E-01	5.12E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 3 - Gas Plant												
Valves	VAP	161	81	1.72E-05	1.39E-03	77	1.57E-04	1.21E-02	3	4.87E-03	1.57E-02	
	LHC	861	431	1.72E-05	7.41E-03	413	1.57E-04	6.48E-02	17	4.87E-03	8.38E-02	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	107	54	6.83E-07	3.67E-05	52	2.59E-04	1.33E-02	2	6.59E-03	1.42E-02	
	LHC	574	287	6.83E-07	1.96E-04	276	2.59E-04	7.13E-02	11	6.59E-03	7.57E-02	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	13	7	5.29E-05	3.51E-04	6	4.91E-03	3.13E-02	0	3.05E-02	8.11E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					9.38E-03			1.93E-01			1.97E-01	4.00E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 4 - Naphtha Hydrotreater												
Valves	VAP	360	180	1.72E-05	3.10E-03	173	1.57E-04	2.71E-02	7	4.87E-03	3.50E-02	
	LHC	923	462	1.72E-05	7.94E-03	443	1.57E-04	6.95E-02	18	4.87E-03	8.99E-02	
	HHC	233	117	1.72E-05	2.01E-03	112	5.21E-04	5.83E-02	5	4.87E-03	2.27E-02	
Flanges	VAP	240	120	6.83E-07	8.20E-05	115	2.59E-04	2.98E-02	5	6.59E-03	3.16E-02	
	LHC	616	308	6.83E-07	2.10E-04	295	2.59E-04	7.65E-02	12	6.59E-03	8.12E-02	
	HHC	156	78	6.83E-07	5.32E-05	75	8.02E-04	5.99E-02	3	6.59E-03	2.05E-02	
Pumps	LHC	5	3	5.29E-05	1.32E-04	2	4.91E-03	1.18E-02	0	3.05E-02	3.06E-03	
	HHC	1	1	5.29E-05	3.34E-05	1	4.91E-03	2.98E-03	0	3.05E-02	7.72E-04	
Compressors	VAP	2	1	8.82E-06	8.82E-06	1	3.85E-04	3.70E-04	0	3.18E-03	1.27E-04	
Subtotal					1.36E-02			3.36E-01			2.85E-01	6.35E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 5 - Catalytic Reformer												
Valves	VAP	218	109	1.72E-05	1.88E-03	105	1.57E-04	1.64E-02	4	4.87E-03	2.13E-02	
	LHC	768	384	1.72E-05	6.60E-03	369	1.57E-04	5.78E-02	15	4.87E-03	7.47E-02	
	HHC	199	99	1.72E-05	1.71E-03	95	5.21E-04	4.96E-02	4	4.87E-03	1.93E-02	
Flanges	VAP	150	75	6.83E-07	5.13E-05	72	2.59E-04	1.87E-02	3	6.59E-03	1.98E-02	
	LHC	528	264	6.83E-07	1.80E-04	253	2.59E-04	6.56E-02	11	6.59E-03	6.96E-02	
	HHC	137	68	6.83E-07	4.67E-05	66	8.02E-04	5.26E-02	3	6.59E-03	1.80E-02	
Pumps	LHC	5	2	5.29E-05	1.31E-04	2	4.91E-03	1.17E-02	0	3.05E-02	3.03E-03	
	HHC	1	1	5.29E-05	3.39E-05	1	4.91E-03	3.02E-03	0	3.05E-02	7.84E-04	
Compressors	VAP	3	2	8.82E-06	1.32E-05	1	3.85E-04	5.55E-04	0	3.18E-03	1.91E-04	
Subtotal					1.06E-02			2.76E-01			2.27E-01	5.13E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 6 - Isomerization (Penex)												
Valves	VAP	177	88	1.72E-05	1.52E-03	85	1.57E-04	1.33E-02	4	4.87E-03	1.72E-02	
	LHC	740	370	1.72E-05	6.36E-03	355	1.57E-04	5.57E-02	15	4.87E-03	7.20E-02	
	HHC	17	8	1.72E-05	1.43E-04	8	5.21E-04	4.17E-03	0	4.87E-03	1.62E-03	
Flanges	VAP	121	61	6.83E-07	4.15E-05	58	2.59E-04	1.51E-02	2	6.59E-03	1.60E-02	
	LHC	509	254	6.83E-07	1.74E-04	244	2.59E-04	6.32E-02	10	6.59E-03	6.71E-02	
	HHC	11	6	6.83E-07	3.92E-06	6	8.02E-04	4.41E-03	0	6.59E-03	1.51E-03	
Pumps	LHC	7	3	5.29E-05	1.84E-04	3	4.91E-03	1.64E-02	0	3.05E-02	4.24E-03	
	HHC	0	0	5.29E-05	4.13E-06	0	4.91E-03	3.68E-04	0	3.05E-02	9.54E-05	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					8.43E-03			1.73E-01			1.80E-01	3.61E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 7 - Hydrogen Production												
Valves	VAP	147	73	1.72E-05	1.26E-03	70	1.57E-04	1.10E-02	3	4.87E-03	1.43E-02	
	LHC	43	22	1.72E-05	3.73E-04	21	1.57E-04	3.26E-03	1	4.87E-03	4.22E-03	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	98	49	6.83E-07	3.34E-05	47	2.59E-04	1.21E-02	2	6.59E-03	1.29E-02	
	LHC	29	14	6.83E-07	9.87E-06	14	2.59E-04	3.59E-03	1	6.59E-03	3.81E-03	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.68E-03			3.00E-02			3.52E-02	6.69E-02

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 8 - Distillate Hydrotreater												
Valves	VAP	370	185	1.72E-05	3.18E-03	178	1.57E-04	2.78E-02	7	4.87E-03	3.60E-02	
	LHC	927	463	1.72E-05	7.97E-03	445	1.57E-04	6.97E-02	19	4.87E-03	9.02E-02	
	HHC	737	368	1.72E-05	6.33E-03	354	5.21E-04	1.84E-01	15	4.87E-03	7.17E-02	
Flanges	VAP	251	125	6.83E-07	8.56E-05	120	2.59E-04	3.11E-02	5	6.59E-03	3.30E-02	
	LHC	628	314	6.83E-07	2.15E-04	301	2.59E-04	7.80E-02	13	6.59E-03	8.28E-02	
	HHC	499	250	6.83E-07	1.71E-04	240	8.02E-04	1.92E-01	10	6.59E-03	6.58E-02	
Pumps	LHC	12	6	5.29E-05	3.24E-04	6	4.91E-03	2.89E-02	0	3.05E-02	7.49E-03	
	HHC	10	5	5.29E-05	2.58E-04	5	4.91E-03	2.30E-02	0	3.05E-02	5.95E-03	
Compressors	VAP	1	1	8.82E-06	4.41E-06	0	3.85E-04	1.85E-04	0	3.18E-03	6.35E-05	
Subtotal					1.85E-02			6.35E-01			3.93E-01	1.05E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 10 - Hydrocracker (Unicracker)												
Valves	VAP	369	185	1.72E-05	3.18E-03	177	1.57E-04	2.78E-02	7	4.87E-03	3.59E-02	
	LHC	1945	973	1.72E-05	1.67E-02	934	1.57E-04	1.46E-01	39	4.87E-03	1.89E-01	
	HHC	1266	633	1.72E-05	1.09E-02	608	5.21E-04	3.16E-01	25	4.87E-03	1.23E-01	
Flanges	VAP	254	127	6.83E-07	8.69E-05	122	2.59E-04	3.16E-02	5	6.59E-03	3.35E-02	
	LHC	1339	670	6.83E-07	4.58E-04	643	2.59E-04	1.66E-01	27	6.59E-03	1.77E-01	
	HHC	872	436	6.83E-07	2.98E-04	418	8.02E-04	3.36E-01	17	6.59E-03	1.15E-01	
Pumps	LHC	16	8	5.29E-05	4.13E-04	8	4.91E-03	3.68E-02	0	3.05E-02	9.55E-03	
	HHC	10	5	5.29E-05	2.69E-04	5	4.91E-03	2.40E-02	0	3.05E-02	6.21E-03	
Compressors	VAP	3	2	8.82E-06	1.32E-05	1	3.85E-04	5.55E-04	0	3.18E-03	1.91E-04	
Subtotal					3.23E-02			1.09E+00			6.89E-01	1.81E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 11 - Sour Water Stripping												
Valves	VAP	2	1	1.72E-05	2.09E-05	1	1.57E-04	1.83E-04	0	4.87E-03	2.37E-04	
	LHC	15	8	1.72E-05	1.29E-04	7	1.57E-04	1.13E-03	0	4.87E-03	1.46E-03	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	2	1	6.83E-07	5.20E-07	1	2.59E-04	1.89E-04	0	6.59E-03	2.01E-04	
	LHC	12	6	6.83E-07	4.10E-06	6	2.59E-04	1.49E-03	0	6.59E-03	1.58E-03	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	2	1	5.29E-05	5.80E-05	1	4.91E-03	5.17E-03	0	3.05E-02	1.34E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					2.13E-04			8.16E-03			4.82E-03	1.32E-02

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 12 - Amine Regeneration												
Valves	VAP	3	1	1.72E-05	2.53E-05	1	1.57E-04	2.21E-04	0	4.87E-03	2.86E-04	
	LHC	10	5	1.72E-05	8.48E-05	5	1.57E-04	7.42E-04	0	4.87E-03	9.60E-04	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	2	1	6.83E-07	6.70E-07	1	2.59E-04	2.44E-04	0	6.59E-03	2.59E-04	
	LHC	12	6	6.83E-07	4.10E-06	6	2.59E-04	1.49E-03	0	6.59E-03	1.58E-03	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	4	2	5.29E-05	1.06E-04	2	4.91E-03	9.43E-03	0	3.05E-02	2.44E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					2.21E-04			1.21E-02			5.53E-03	1.79E-02

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 14 - Delayed Coker												
Valves	VAP	490	245	1.72E-05	4.21E-03	235	1.57E-04	3.69E-02	10	4.87E-03	4.77E-02	
	LHC	934	467	1.72E-05	8.03E-03	448	1.57E-04	7.03E-02	19	4.87E-03	9.09E-02	
	HHC	1634	817	1.72E-05	1.41E-02	785	5.21E-04	4.09E-01	33	4.87E-03	1.59E-01	
Flanges	VAP	340	170	6.83E-07	1.16E-04	163	2.59E-04	4.22E-02	7	6.59E-03	4.48E-02	
	LHC	648	324	6.83E-07	2.21E-04	311	2.59E-04	8.05E-02	13	6.59E-03	8.54E-02	
	HHC	1134	567	6.83E-07	3.88E-04	544	8.02E-04	4.37E-01	23	6.59E-03	1.50E-01	
Pumps	LHC	10	5	5.29E-05	2.77E-04	5	4.91E-03	2.47E-02	0	3.05E-02	6.40E-03	
	HHC	18	9	5.29E-05	4.85E-04	9	4.91E-03	4.33E-02	0	3.05E-02	1.12E-02	
Compressors	VAP	1	1	8.82E-06	4.41E-06	0	3.85E-04	1.85E-04	0	3.18E-03	6.35E-05	
Subtotal					2.78E-02			1.14E+00			5.95E-01	1.77E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 15 - Butane Conversion Unit												
Valves	VAP	578	289	1.72E-05	4.97E-03	277	1.57E-04	4.35E-02	12	4.87E-03	5.63E-02	
	LHC	1691	846	1.72E-05	1.45E-02	812	1.57E-04	1.27E-01	34	4.87E-03	1.65E-01	
	HHC	432	216	1.72E-05	3.71E-03	207	5.21E-04	1.08E-01	9	4.87E-03	4.20E-02	
Flanges	VAP	390	195	6.83E-07	1.33E-04	187	2.59E-04	4.85E-02	8	6.59E-03	5.14E-02	
	LHC	1144	572	6.83E-07	3.91E-04	549	2.59E-04	1.42E-01	23	6.59E-03	1.51E-01	
	HHC	292	146	6.83E-07	9.98E-05	140	8.02E-04	1.12E-01	6	6.59E-03	3.85E-02	
Pumps	LHC	10	5	5.29E-05	2.65E-04	5	4.91E-03	2.36E-02	0	3.05E-02	6.11E-03	
	HHC	3	2	5.29E-05	7.94E-05	1	4.91E-03	7.07E-03	0	3.05E-02	1.83E-03	
Compressors	VAP	5	3	8.82E-06	2.20E-05	2	3.85E-04	9.25E-04	0	3.18E-03	3.18E-04	
Subtotal					2.42E-02			6.13E-01			5.12E-01	1.15E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 16 - Benzene Reduction Unit												
Valves	VAP	177	88	1.72E-05	1.52E-03	85	1.57E-04	1.33E-02	4	4.87E-03	1.72E-02	
	LHC	740	370	1.72E-05	6.36E-03	355	1.57E-04	5.57E-02	15	4.87E-03	7.20E-02	
	HHC	17	8	1.72E-05	1.43E-04	8	5.21E-04	4.17E-03	0	4.87E-03	1.62E-03	
Flanges	VAP	121	61	6.83E-07	4.15E-05	58	2.59E-04	1.51E-02	2	6.59E-03	1.60E-02	
	LHC	509	254	6.83E-07	1.74E-04	244	2.59E-04	6.32E-02	10	6.59E-03	6.71E-02	
	HHC	11	6	6.83E-07	3.92E-06	6	8.02E-04	4.41E-03	0	6.59E-03	1.51E-03	
Pumps	LHC	7	3	5.29E-05	1.84E-04	3	4.91E-03	1.64E-02	0	3.05E-02	4.24E-03	
	HHC	0	0	5.29E-05	4.13E-06	0	4.91E-03	3.68E-04	0	3.05E-02	9.54E-05	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					8.43E-03			1.73E-01			1.80E-01	3.61E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 26 - Wastewater Treatment Piping												
Valves	VAP	63	32	1.72E-05	5.45E-04	30	1.57E-04	4.76E-03	1	4.87E-03	6.16E-03	
	LHC	63	32	1.72E-05	5.45E-04	30	1.57E-04	4.76E-03	1	4.87E-03	6.16E-03	
	HHC	463	232	1.72E-05	3.98E-03	222	5.21E-04	1.16E-01	9	4.87E-03	4.51E-02	
Flanges	VAP	41	20	6.83E-07	1.40E-05	20	2.59E-04	5.09E-03	1	6.59E-03	5.40E-03	
	LHC	41	20	6.83E-07	1.40E-05	20	2.59E-04	5.09E-03	1	6.59E-03	5.40E-03	
	HHC	300	150	6.83E-07	1.02E-04	144	8.02E-04	1.15E-01	6	6.59E-03	3.95E-02	
Pumps	LHC	0	0	5.29E-05	1.18E-05	0	4.91E-03	1.05E-03	0	3.05E-02	2.73E-04	
	HHC	3	2	5.29E-05	8.65E-05	2	4.91E-03	7.71E-03	0	3.05E-02	2.00E-03	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					5.30E-03			2.60E-01			1.10E-01	3.75E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 41 - Crude Oil Metering Station												
Valves	VAP	7	4	1.72E-05	6.02E-05	3	1.57E-04	5.27E-04	0	4.87E-03	6.81E-04	
	LHC	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	HHC	63	32	1.72E-05	5.42E-04	30	5.21E-04	1.57E-02	1	4.87E-03	6.13E-03	
Flanges	VAP	6	3	6.83E-07	2.05E-06	3	2.59E-04	7.45E-04	0	6.59E-03	7.91E-04	
	LHC	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	HHC	54	27	6.83E-07	1.85E-05	26	8.02E-04	2.08E-02	1	6.59E-03	7.12E-03	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					6.22E-04			3.78E-02			1.47E-02	5.32E-02

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 42 - Tank Farm Piping												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	2440	1220	1.72E-05	2.10E-02	1171	1.57E-04	1.84E-01	49	4.87E-03	2.37E-01	
	HHC	1997	998	1.72E-05	1.72E-02	958	5.21E-04	4.99E-01	40	4.87E-03	1.94E-01	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	1851	925	6.83E-07	6.32E-04	888	2.59E-04	2.30E-01	37	6.59E-03	2.44E-01	
	HHC	1514	757	6.83E-07	5.17E-04	727	8.02E-04	5.83E-01	30	6.59E-03	2.00E-01	
Pumps	LHC	48	24	5.29E-05	1.27E-03	23	4.91E-03	1.13E-01	1	3.05E-02	2.94E-02	
	HHC	39	20	5.29E-05	1.04E-03	19	4.91E-03	9.28E-02	1	3.05E-02	2.40E-02	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					4.16E-02			1.70E+00			9.29E-01	2.67E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 43 - Slop and Flushing Oil Systems												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	459	230	1.72E-05	3.95E-03	220	1.57E-04	3.45E-02	9	4.87E-03	4.47E-02	
	HHC	1189	595	1.72E-05	1.02E-02	571	5.21E-04	2.97E-01	24	4.87E-03	1.16E-01	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	348	174	6.83E-07	1.19E-04	167	2.59E-04	4.33E-02	7	6.59E-03	4.59E-02	
	HHC	902	451	6.83E-07	3.08E-04	433	8.02E-04	3.47E-01	18	6.59E-03	1.19E-01	
Pumps	LHC	3	2	5.29E-05	8.38E-05	2	4.91E-03	7.47E-03	0	3.05E-02	1.93E-03	
	HHC	8	4	5.29E-05	2.17E-04	4	4.91E-03	1.93E-02	0	3.05E-02	5.01E-03	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.49E-02			7.49E-01			3.32E-01	1.10E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 44 - Vapor Recovery System Pipework												
Valves	VAP	198	99	1.72E-05	1.70E-03	95	1.57E-04	1.49E-02	4	4.87E-03	1.92E-02	
	LHC	179	89	1.72E-05	1.53E-03	86	1.57E-04	1.34E-02	4	4.87E-03	1.74E-02	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	141	71	6.83E-07	4.83E-05	68	2.59E-04	1.75E-02	3	6.59E-03	1.86E-02	
	LHC	128	64	6.83E-07	4.36E-05	61	2.59E-04	1.58E-02	3	6.59E-03	1.68E-02	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	8	4	5.29E-05	2.02E-04	4	4.91E-03	1.80E-02	0	3.05E-02	4.67E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					3.53E-03			7.97E-02			7.67E-02	1.60E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 45 - Gasoline Blending Pipework												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	50	25	1.72E-05	4.30E-04	24	1.57E-04	3.76E-03	1	4.87E-03	4.87E-03	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	150	75	6.83E-07	5.13E-05	72	2.59E-04	1.86E-02	3	6.59E-03	1.98E-02	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	25	13	5.29E-05	6.61E-04	12	4.91E-03	5.89E-02	1	3.05E-02	1.53E-02	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.14E-03			8.13E-02			3.99E-02	1.22E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 46 - Rail Loading/Unloading Pipework												
Valves	VAP	520	260	1.72E-05	4.47E-03	250	1.57E-04	3.91E-02	10	4.87E-03	5.06E-02	
	LHC	1700	850	1.72E-05	1.46E-02	816	1.57E-04	1.28E-01	34	4.87E-03	1.65E-01	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	607	303	6.83E-07	2.07E-04	291	2.59E-04	7.54E-02	12	6.59E-03	8.00E-02	
	LHC	1983	992	6.83E-07	6.78E-04	952	2.59E-04	2.46E-01	40	6.59E-03	2.61E-01	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					2.00E-02			4.89E-01			5.58E-01	1.07E+00

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 47 - Truck Loading/Unloading Pipework												
Valves	VAP	340	170	1.72E-05	2.92E-03	163	1.57E-04	2.56E-02	7	4.87E-03	3.31E-02	
	LHC	1300	650	1.72E-05	1.12E-02	624	1.57E-04	9.78E-02	26	4.87E-03	1.27E-01	
	HHC	40	20	1.72E-05	3.44E-04	19	5.21E-04	1.00E-02	1	4.87E-03	3.89E-03	
Flanges	VAP	383	191	6.83E-07	1.31E-04	184	2.59E-04	4.75E-02	8	6.59E-03	5.04E-02	
	LHC	1463	731	6.83E-07	5.00E-04	702	2.59E-04	1.82E-01	29	6.59E-03	1.93E-01	
	HHC	45	23	6.83E-07	1.54E-05	22	8.02E-04	1.73E-02	1	6.59E-03	5.93E-03	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.51E-02			3.80E-01			4.13E-01	8.08E-01

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 51 - Closed Drain System Pipework												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	76	38	1.72E-05	6.53E-04	36	1.57E-04	5.72E-03	2	4.87E-03	7.40E-03	
	HHC	40	20	1.72E-05	3.44E-04	19	5.21E-04	1.00E-02	1	4.87E-03	3.89E-03	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	87	43	6.83E-07	2.97E-05	42	2.59E-04	1.08E-02	2	6.59E-03	1.15E-02	
	HHC	46	23	6.83E-07	1.56E-05	22	8.02E-04	1.76E-02	1	6.59E-03	6.03E-03	
Pumps	LHC	4	2	5.29E-05	1.01E-04	2	4.91E-03	8.96E-03	0	3.05E-02	2.32E-03	
	HHC	2	1	5.29E-05	5.29E-05	1	4.91E-03	4.72E-03	0	3.05E-02	1.22E-03	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.20E-03			5.78E-02			3.23E-02	9.13E-02

Table III-N-3. Hourly VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 10,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 60 - Product Pipeline												
Valves	VAP	20	10	1.72E-05	1.72E-04	10	1.57E-04	1.50E-03	0	4.87E-03	1.95E-03	
	LHC	150	75	1.72E-05	1.29E-03	72	1.57E-04	1.13E-02	3	4.87E-03	1.46E-02	
	HHC	90	45	1.72E-05	7.74E-04	43	5.21E-04	2.25E-02	2	4.87E-03	8.76E-03	
Flanges	VAP	23	12	6.83E-07	7.86E-06	11	2.59E-04	2.86E-03	0	6.59E-03	3.03E-03	
	LHC	180	90	6.83E-07	6.15E-05	86	2.59E-04	2.24E-02	4	6.59E-03	2.37E-02	
	HHC	80	40	6.83E-07	2.73E-05	38	8.02E-04	3.08E-02	2	6.59E-03	1.05E-02	
Pumps	LHC	10	5	5.29E-05	2.65E-04	5	4.91E-03	2.36E-02	0	3.05E-02	6.11E-03	
	HHC	5	2	5.29E-05	1.27E-04	2	4.91E-03	1.13E-02	0	3.05E-02	2.93E-03	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					2.72E-03			1.26E-01			7.17E-02	2.01E-01
TOTAL												16.82

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 1 - Atmospheric Distillation												
Valves	VAP	427	421	1.72E-05	7.24E-03	4	1.57E-04	6.69E-04	1	4.87E-03	6.23E-03	
	LHC	1182	1166	1.72E-05	2.01E-02	12	1.57E-04	1.85E-03	4	4.87E-03	1.72E-02	
	HHC	1280	1255	1.72E-05	2.16E-02	13	5.21E-04	6.67E-03	13	4.87E-03	6.23E-02	
Flanges	VAP	288	284	6.83E-07	1.94E-04	3	2.59E-04	7.45E-04	1	6.59E-03	5.69E-03	
	LHC	797	787	6.83E-07	5.38E-04	8	2.59E-04	2.06E-03	2	6.59E-03	1.58E-02	
	HHC	863	846	6.83E-07	5.78E-04	9	8.02E-04	6.93E-03	9	6.59E-03	5.69E-02	
Pumps	LHC	9	4	5.29E-05	2.38E-04	4	4.91E-03	2.21E-02	0	3.05E-02	2.77E-03	
	HHC	10	10	5.29E-05	5.09E-04	0	4.91E-03	4.83E-04	0	3.05E-02	3.00E-03	
Compressors	VAP	1	0	8.82E-06	0.00E+00	1	3.85E-04	3.81E-04	0	3.18E-03	3.18E-05	
Subtotal					5.09E-02			4.18E-02			1.70E-01	2.63E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 2 - Vacuum Distillation												
Valves	VAP	113	111	1.72E-05	1.91E-03	1	1.57E-04	1.77E-04	0	4.87E-03	1.65E-03	
	LHC	88	87	1.72E-05	1.50E-03	1	1.57E-04	1.38E-04	0	4.87E-03	1.29E-03	
	HHC	585	573	1.72E-05	9.86E-03	6	5.21E-04	3.05E-03	6	4.87E-03	2.85E-02	
Flanges	VAP	80	79	6.83E-07	5.37E-05	1	2.59E-04	2.06E-04	0	6.59E-03	1.57E-03	
	LHC	62	61	6.83E-07	4.20E-05	1	2.59E-04	1.61E-04	0	6.59E-03	1.23E-03	
	HHC	413	405	6.83E-07	2.77E-04	4	8.02E-04	3.31E-03	4	6.59E-03	2.72E-02	
Pumps	LHC	1	0	5.29E-05	1.90E-05	0	4.91E-03	1.77E-03	0	3.05E-02	2.22E-04	
	HHC	5	5	5.29E-05	2.50E-04	0	4.91E-03	2.37E-04	0	3.05E-02	1.47E-03	
Compressors	VAP	2	0	8.82E-06	0.00E+00	2	3.85E-04	7.63E-04	0	3.18E-03	6.35E-05	
Subtotal					1.39E-02			9.81E-03			6.32E-02	8.69E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 3 - Gas Plant												
Valves	VAP	161	159	1.72E-05	2.73E-03	2	1.57E-04	2.52E-04	0	4.87E-03	2.35E-03	
	LHC	861	850	1.72E-05	1.46E-02	9	1.57E-04	1.35E-03	3	4.87E-03	1.26E-02	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	107	106	6.83E-07	7.24E-05	1	2.59E-04	2.78E-04	0	6.59E-03	2.12E-03	
	LHC	574	567	6.83E-07	3.87E-04	6	2.59E-04	1.49E-03	2	6.59E-03	1.14E-02	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	13	7	5.29E-05	3.48E-04	7	4.91E-03	3.23E-02	0	3.05E-02	4.06E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.82E-02			3.57E-02			3.25E-02	8.63E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 4 - Naphtha Hydrotreater												
Valves	VAP	360	355	1.72E-05	6.11E-03	4	1.57E-04	5.64E-04	1	4.87E-03	5.26E-03	
	LHC	923	911	1.72E-05	1.57E-02	9	1.57E-04	1.45E-03	3	4.87E-03	1.35E-02	
	HHC	233	229	1.72E-05	3.93E-03	2	5.21E-04	1.21E-03	2	4.87E-03	1.14E-02	
Flanges	VAP	240	237	6.83E-07	1.62E-04	2	2.59E-04	6.21E-04	1	6.59E-03	4.75E-03	
	LHC	616	608	6.83E-07	4.15E-04	6	2.59E-04	1.59E-03	2	6.59E-03	1.22E-02	
	HHC	156	152	6.83E-07	1.04E-04	2	8.02E-04	1.25E-03	2	6.59E-03	1.03E-02	
Pumps	LHC	5	2	5.29E-05	1.31E-04	2	4.91E-03	1.22E-02	0	3.05E-02	1.53E-03	
	HHC	1	1	5.29E-05	6.55E-05	0	4.91E-03	6.21E-05	0	3.05E-02	3.86E-04	
Compressors	VAP	2	0	8.82E-06	0.00E+00	2	3.85E-04	7.63E-04	0	3.18E-03	6.35E-05	
Subtotal					2.66E-02			1.97E-02			5.92E-02	1.06E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 5 - Catalytic Reformer												
Valves	VAP	218	216	1.72E-05	3.71E-03	2	1.57E-04	3.42E-04	1	4.87E-03	3.19E-03	
	LHC	768	758	1.72E-05	1.30E-02	8	1.57E-04	1.20E-03	2	4.87E-03	1.12E-02	
	HHC	199	195	1.72E-05	3.35E-03	2	5.21E-04	1.03E-03	2	4.87E-03	9.66E-03	
Flanges	VAP	150	148	6.83E-07	1.01E-04	2	2.59E-04	3.89E-04	0	6.59E-03	2.97E-03	
	LHC	528	521	6.83E-07	3.56E-04	5	2.59E-04	1.37E-03	2	6.59E-03	1.04E-02	
	HHC	137	134	6.83E-07	9.15E-05	1	8.02E-04	1.10E-03	1	6.59E-03	9.00E-03	
Pumps	LHC	5	2	5.29E-05	1.30E-04	2	4.91E-03	1.21E-02	0	3.05E-02	1.51E-03	
	HHC	1	1	5.29E-05	6.65E-05	0	4.91E-03	6.30E-05	0	3.05E-02	3.92E-04	
Compressors	VAP	3	0	8.82E-06	2.20E-21	3	3.85E-04	1.14E-03	0	3.18E-03	9.53E-05	
Subtotal					2.08E-02			1.87E-02			4.85E-02	8.80E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 6 - Isomerization (Penex)												
Valves	VAP	177	174	1.72E-05	3.00E-03	2	1.57E-04	2.77E-04	1	4.87E-03	2.58E-03	
	LHC	740	730	1.72E-05	1.26E-02	7	1.57E-04	1.16E-03	2	4.87E-03	1.08E-02	
	HHC	17	16	1.72E-05	2.81E-04	0	5.21E-04	8.68E-05	0	4.87E-03	8.11E-04	
Flanges	VAP	121	120	6.83E-07	8.19E-05	1	2.59E-04	3.14E-04	0	6.59E-03	2.40E-03	
	LHC	509	502	6.83E-07	3.43E-04	5	2.59E-04	1.32E-03	2	6.59E-03	1.01E-02	
	HHC	11	11	6.83E-07	7.67E-06	0	8.02E-04	9.19E-05	0	6.59E-03	7.55E-04	
Pumps	LHC	7	3	5.29E-05	1.82E-04	3	4.91E-03	1.69E-02	0	3.05E-02	2.12E-03	
	HHC	0	0	5.29E-05	8.10E-06	0	4.91E-03	7.68E-06	0	3.05E-02	4.77E-05	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.65E-02			2.01E-02			2.96E-02	6.62E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 7 - Hydrogen Production												
Valves	VAP	147	145	1.72E-05	2.49E-03	1	1.57E-04	2.30E-04	0	4.87E-03	2.14E-03	
	LHC	43	43	1.72E-05	7.35E-04	0	1.57E-04	6.79E-05	0	4.87E-03	6.33E-04	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	98	97	6.83E-07	6.60E-05	1	2.59E-04	2.53E-04	0	6.59E-03	1.93E-03	
	LHC	29	29	6.83E-07	1.95E-05	0	2.59E-04	7.48E-05	0	6.59E-03	5.71E-04	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					3.31E-03			6.26E-04			5.28E-03	9.21E-03

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 8 - Distillate Hydrotreater												
Valves	VAP	370	365	1.72E-05	6.28E-03	4	1.57E-04	5.80E-04	1	4.87E-03	5.40E-03	
	LHC	927	915	1.72E-05	1.57E-02	9	1.57E-04	1.45E-03	3	4.87E-03	1.35E-02	
	HHC	737	722	1.72E-05	1.24E-02	7	5.21E-04	3.84E-03	7	4.87E-03	3.58E-02	
Flanges	VAP	251	247	6.83E-07	1.69E-04	3	2.59E-04	6.49E-04	1	6.59E-03	4.96E-03	
	LHC	628	620	6.83E-07	4.23E-04	6	2.59E-04	1.62E-03	2	6.59E-03	1.24E-02	
	HHC	499	489	6.83E-07	3.34E-04	5	8.02E-04	4.00E-03	5	6.59E-03	3.29E-02	
Pumps	LHC	12	6	5.29E-05	3.21E-04	6	4.91E-03	2.98E-02	0	3.05E-02	3.74E-03	
	HHC	10	10	5.29E-05	5.05E-04	0	4.91E-03	4.79E-04	0	3.05E-02	2.98E-03	
Compressors	VAP	1	0	8.82E-06	0.00E+00	1	3.85E-04	3.81E-04	0	3.18E-03	3.18E-05	
Subtotal					3.62E-02			4.28E-02			1.12E-01	1.91E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 10 - Hydrocracker (Unicracker)												
Valves	VAP	369	364	1.72E-05	6.27E-03	4	1.57E-04	5.79E-04	1	4.87E-03	5.39E-03	
	LHC	1945	1920	1.72E-05	3.30E-02	19	1.57E-04	3.05E-03	6	4.87E-03	2.84E-02	
	HHC	1266	1241	1.72E-05	2.13E-02	13	5.21E-04	6.59E-03	13	4.87E-03	6.16E-02	
Flanges	VAP	254	251	6.83E-07	1.72E-04	3	2.59E-04	6.58E-04	1	6.59E-03	5.03E-03	
	LHC	1339	1322	6.83E-07	9.04E-04	13	2.59E-04	3.47E-03	4	6.59E-03	2.65E-02	
	HHC	872	854	6.83E-07	5.84E-04	9	8.02E-04	7.00E-03	9	6.59E-03	5.75E-02	
Pumps	LHC	16	8	5.29E-05	4.09E-04	8	4.91E-03	3.80E-02	0	3.05E-02	4.77E-03	
	HHC	10	10	5.29E-05	5.27E-04	0	4.91E-03	5.00E-04	0	3.05E-02	3.11E-03	
Compressors	VAP	3	0	8.82E-06	2.20E-21	3	3.85E-04	1.14E-03	0	3.18E-03	9.53E-05	
Subtotal					6.32E-02			6.10E-02			1.92E-01	3.17E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 11 - Sour Water Stripping												
Valves	VAP	2	2	1.72E-05	4.13E-05	0	1.57E-04	3.82E-06	0	4.87E-03	3.55E-05	
	LHC	15	15	1.72E-05	2.55E-04	0	1.57E-04	2.35E-05	0	4.87E-03	2.19E-04	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	2	2	6.83E-07	1.03E-06	0	2.59E-04	3.94E-06	0	6.59E-03	3.01E-05	
	LHC	12	12	6.83E-07	8.09E-06	0	2.59E-04	3.11E-05	0	6.59E-03	2.37E-04	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	2	1	5.29E-05	5.74E-05	1	4.91E-03	5.33E-03	0	3.05E-02	6.70E-04	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					3.62E-04			5.39E-03			1.19E-03	6.95E-03

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 12 - Amine Regeneration												
Valves	VAP	3	3	1.72E-05	4.99E-05	0	1.57E-04	4.61E-06	0	4.87E-03	4.30E-05	
	LHC	10	10	1.72E-05	1.67E-04	0	1.57E-04	1.55E-05	0	4.87E-03	1.44E-04	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	2	2	6.83E-07	1.32E-06	0	2.59E-04	5.08E-06	0	6.59E-03	3.88E-05	
	LHC	12	12	6.83E-07	8.09E-06	0	2.59E-04	3.11E-05	0	6.59E-03	2.37E-04	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	4	2	5.29E-05	1.05E-04	2	4.91E-03	9.73E-03	0	3.05E-02	1.22E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					3.32E-04			9.78E-03			1.68E-03	1.18E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 14 - Delayed Coker												
Valves	VAP	490	484	1.72E-05	8.32E-03	5	1.57E-04	7.68E-04	1	4.87E-03	7.15E-03	
	LHC	934	922	1.72E-05	1.59E-02	9	1.57E-04	1.46E-03	3	4.87E-03	1.36E-02	
	HHC	1634	1602	1.72E-05	2.75E-02	16	5.21E-04	8.51E-03	16	4.87E-03	7.95E-02	
Flanges	VAP	340	336	6.83E-07	2.29E-04	3	2.59E-04	8.80E-04	1	6.59E-03	6.72E-03	
	LHC	648	640	6.83E-07	4.37E-04	6	2.59E-04	1.68E-03	2	6.59E-03	1.28E-02	
	HHC	1134	1111	6.83E-07	7.60E-04	11	8.02E-04	9.10E-03	11	6.59E-03	7.48E-02	
Pumps	LHC	10	5	5.29E-05	2.75E-04	5	4.91E-03	2.55E-02	0	3.05E-02	3.20E-03	
	HHC	18	18	5.29E-05	9.51E-04	0	4.91E-03	9.01E-04	0	3.05E-02	5.60E-03	
Compressors	VAP	1	0	8.82E-06	0.00E+00	1	3.85E-04	3.81E-04	0	3.18E-03	3.18E-05	
Subtotal					5.44E-02			4.92E-02			2.03E-01	3.07E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 15 - Butane Conversion Unit												
Valves	VAP	578	570	1.72E-05	9.81E-03	6	1.57E-04	9.06E-04	2	4.87E-03	8.44E-03	
	LHC	1691	1669	1.72E-05	2.87E-02	17	1.57E-04	2.65E-03	5	4.87E-03	2.47E-02	
	HHC	432	423	1.72E-05	7.28E-03	4	5.21E-04	2.25E-03	4	4.87E-03	2.10E-02	
Flanges	VAP	390	385	6.83E-07	2.63E-04	4	2.59E-04	1.01E-03	1	6.59E-03	7.71E-03	
	LHC	1144	1129	6.83E-07	7.72E-04	11	2.59E-04	2.96E-03	3	6.59E-03	2.26E-02	
	HHC	292	286	6.83E-07	1.96E-04	3	8.02E-04	2.34E-03	3	6.59E-03	1.92E-02	
Pumps	LHC	10	5	5.29E-05	2.62E-04	5	4.91E-03	2.43E-02	0	3.05E-02	3.05E-03	
	HHC	3	3	5.29E-05	1.56E-04	0	4.91E-03	1.47E-04	0	3.05E-02	9.16E-04	
Compressors	VAP	5	0	8.82E-06	-1.59E-21	5	3.85E-04	1.91E-03	0	3.18E-03	1.59E-04	
Subtotal					4.74E-02			3.85E-02			1.08E-01	1.94E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 16 - Benzene Reduction Unit												
Valves	VAP	177	174	1.72E-05	3.00E-03	2	1.57E-04	2.77E-04	1	4.87E-03	2.58E-03	
	LHC	740	730	1.72E-05	1.26E-02	7	1.57E-04	1.16E-03	2	4.87E-03	1.08E-02	
	HHC	17	16	1.72E-05	2.81E-04	0	5.21E-04	8.68E-05	0	4.87E-03	8.11E-04	
Flanges	VAP	121	120	6.83E-07	8.19E-05	1	2.59E-04	3.14E-04	0	6.59E-03	2.40E-03	
	LHC	509	502	6.83E-07	3.43E-04	5	2.59E-04	1.32E-03	2	6.59E-03	1.01E-02	
	HHC	11	11	6.83E-07	7.67E-06	0	8.02E-04	9.19E-05	0	6.59E-03	7.55E-04	
Pumps	LHC	7	3	5.29E-05	1.82E-04	3	4.91E-03	1.69E-02	0	3.05E-02	2.12E-03	
	HHC	0	0	5.29E-05	8.10E-06	0	4.91E-03	7.68E-06	0	3.05E-02	4.77E-05	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.65E-02			2.01E-02			2.96E-02	6.62E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 26 - Wastewater Treatment Piping												
Valves	VAP	63	63	1.72E-05	1.07E-03	1	1.57E-04	9.93E-05	0	4.87E-03	9.25E-04	
	LHC	63	63	1.72E-05	1.07E-03	1	1.57E-04	9.93E-05	0	4.87E-03	9.25E-04	
	HHC	463	454	1.72E-05	7.81E-03	5	5.21E-04	2.41E-03	5	4.87E-03	2.25E-02	
Flanges	VAP	41	40	6.83E-07	2.76E-05	0	2.59E-04	1.06E-04	0	6.59E-03	8.10E-04	
	LHC	41	40	6.83E-07	2.76E-05	0	2.59E-04	1.06E-04	0	6.59E-03	8.10E-04	
	HHC	300	294	6.83E-07	2.01E-04	3	8.02E-04	2.41E-03	3	6.59E-03	1.98E-02	
Pumps	LHC	0	0	5.29E-05	1.17E-05	0	4.91E-03	1.09E-03	0	3.05E-02	1.37E-04	
	HHC	3	3	5.29E-05	1.70E-04	0	4.91E-03	1.61E-04	0	3.05E-02	9.99E-04	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.04E-02			6.48E-03			4.69E-02	6.38E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 41 - Crude Oil Metering Station												
Valves	VAP	7	7	1.72E-05	1.19E-04	0	1.57E-04	1.10E-05	0	4.87E-03	1.02E-04	
	LHC	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	HHC	63	62	1.72E-05	1.06E-03	1	5.21E-04	3.28E-04	1	4.87E-03	3.07E-03	
Flanges	VAP	6	6	6.83E-07	4.05E-06	0	2.59E-04	1.55E-05	0	6.59E-03	1.19E-04	
	LHC	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	HHC	54	53	6.83E-07	3.62E-05	1	8.02E-04	4.33E-04	1	6.59E-03	3.56E-03	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.22E-03			7.88E-04			6.85E-03	8.85E-03

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 42 - Tank Farm Piping												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	2440	2409	1.72E-05	4.14E-02	24	1.57E-04	3.82E-03	7	4.87E-03	3.56E-02	
	HHC	1997	1957	1.72E-05	3.36E-02	20	5.21E-04	1.04E-02	20	4.87E-03	9.72E-02	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	1851	1827	6.83E-07	1.25E-03	19	2.59E-04	4.79E-03	6	6.59E-03	3.66E-02	
	HHC	1514	1484	6.83E-07	1.01E-03	15	8.02E-04	1.22E-02	15	6.59E-03	9.98E-02	
Pumps	LHC	48	24	5.29E-05	1.26E-03	24	4.91E-03	1.17E-01	0	3.05E-02	1.47E-02	
	HHC	39	39	5.29E-05	2.04E-03	0	4.91E-03	1.93E-03	0	3.05E-02	1.20E-02	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					8.06E-02			1.50E-01			2.96E-01	5.27E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 43 - Slop and Flushing Oil Systems												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	459	453	1.72E-05	7.79E-03	5	1.57E-04	7.20E-04	1	4.87E-03	6.70E-03	
	HHC	1189	1165	1.72E-05	2.00E-02	12	5.21E-04	6.19E-03	12	4.87E-03	5.79E-02	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	348	344	6.83E-07	2.35E-04	3	2.59E-04	9.02E-04	1	6.59E-03	6.89E-03	
	HHC	902	884	6.83E-07	6.04E-04	9	8.02E-04	7.24E-03	9	6.59E-03	5.95E-02	
Pumps	LHC	3	2	5.29E-05	8.29E-05	2	4.91E-03	7.70E-03	0	3.05E-02	9.67E-04	
	HHC	8	8	5.29E-05	4.25E-04	0	4.91E-03	4.03E-04	0	3.05E-02	2.50E-03	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					2.92E-02			2.32E-02			1.34E-01	1.87E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 44 - Vapor Recovery System Pipework												
Valves	VAP	198	195	1.72E-05	3.36E-03	2	1.57E-04	3.10E-04	1	4.87E-03	2.89E-03	
	LHC	179	176	1.72E-05	3.03E-03	2	1.57E-04	2.80E-04	1	4.87E-03	2.61E-03	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	141	139	6.83E-07	9.53E-05	1	2.59E-04	3.66E-04	0	6.59E-03	2.79E-03	
	LHC	128	126	6.83E-07	8.60E-05	1	2.59E-04	3.30E-04	0	6.59E-03	2.52E-03	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	8	4	5.29E-05	2.00E-04	4	4.91E-03	1.86E-02	0	3.05E-02	2.34E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					6.77E-03			1.99E-02			1.31E-02	3.98E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 45 - Gasoline Blending Pipework												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	50	49	1.72E-05	8.49E-04	1	1.57E-04	7.84E-05	0	4.87E-03	7.30E-04	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	150	148	6.83E-07	1.01E-04	2	2.59E-04	3.88E-04	0	6.59E-03	2.97E-03	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	25	12	5.29E-05	6.55E-04	12	4.91E-03	6.08E-02	0	3.05E-02	7.64E-03	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					1.60E-03			6.13E-02			1.13E-02	7.42E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 46 - Rail Loading/Unloading Pipework												
Valves	VAP	520	513	1.72E-05	8.83E-03	5	1.57E-04	8.15E-04	2	4.87E-03	7.59E-03	
	LHC	1700	1678	1.72E-05	2.89E-02	17	1.57E-04	2.66E-03	5	4.87E-03	2.48E-02	
	HHC	0	0	1.72E-05	0.00E+00	0	5.21E-04	0.00E+00	0	4.87E-03	0.00E+00	
Flanges	VAP	607	599	6.83E-07	4.09E-04	6	2.59E-04	1.57E-03	2	6.59E-03	1.20E-02	
	LHC	1983	1958	6.83E-07	1.34E-03	20	2.59E-04	5.13E-03	6	6.59E-03	3.92E-02	
	HHC	0	0	6.83E-07	0.00E+00	0	8.02E-04	0.00E+00	0	6.59E-03	0.00E+00	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					3.94E-02			1.02E-02			8.36E-02	1.33E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 47 - Truck Loading/Unloading Pipework												
Valves	VAP	340	336	1.72E-05	5.77E-03	3	1.57E-04	5.33E-04	1	4.87E-03	4.96E-03	
	LHC	1300	1283	1.72E-05	2.21E-02	13	1.57E-04	2.04E-03	4	4.87E-03	1.90E-02	
	HHC	40	39	1.72E-05	6.74E-04	0	5.21E-04	2.08E-04	0	4.87E-03	1.95E-03	
Flanges	VAP	383	378	6.83E-07	2.58E-04	4	2.59E-04	9.90E-04	1	6.59E-03	7.56E-03	
	LHC	1463	1443	6.83E-07	9.87E-04	15	2.59E-04	3.79E-03	4	6.59E-03	2.89E-02	
	HHC	45	44	6.83E-07	3.01E-05	0	8.02E-04	3.61E-04	0	6.59E-03	2.97E-03	
Pumps	LHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
	HHC	0	0	5.29E-05	0.00E+00	0	4.91E-03	0.00E+00	0	3.05E-02	0.00E+00	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					2.98E-02			7.92E-03			6.53E-02	1.03E-01

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 51 - Closed Drain System Pipework												
Valves	VAP	0	0	1.72E-05	0.00E+00	0	1.57E-04	0.00E+00	0	4.87E-03	0.00E+00	
	LHC	76	75	1.72E-05	1.29E-03	1	1.57E-04	1.19E-04	0	4.87E-03	1.11E-03	
	HHC	40	39	1.72E-05	6.74E-04	0	5.21E-04	2.08E-04	0	4.87E-03	1.95E-03	
Flanges	VAP	0	0	6.83E-07	0.00E+00	0	2.59E-04	0.00E+00	0	6.59E-03	0.00E+00	
	LHC	87	86	6.83E-07	5.86E-05	1	2.59E-04	2.25E-04	0	6.59E-03	1.72E-03	
	HHC	46	45	6.83E-07	3.06E-05	0	8.02E-04	3.67E-04	0	6.59E-03	3.01E-03	
Pumps	LHC	4	2	5.29E-05	9.95E-05	2	4.91E-03	9.24E-03	0	3.05E-02	1.16E-03	
	HHC	2	2	5.29E-05	1.04E-04	0	4.91E-03	9.82E-05	0	3.05E-02	6.11E-04	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					2.26E-03			1.03E-02			9.56E-03	2.21E-02

Table III-N-4. Annual VOC Emissions from Equipment Leaks

Component	Service	Total Quantity	Default Zero			Leaking @ 100/500 ppmv			Leaking @ 5,000 ppmv			Total VOC Emission Rate (lb/hr)
			Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	Quantity	Emission Factor (lbVOC/hr/component)	VOC Emission Rate (lb/hr)	
Unit 60 - Product Pipeline												
Valves	VAP	20	20	1.72E-05	3.39E-04	0	1.57E-04	3.13E-05	0	4.87E-03	2.92E-04	
	LHC	150	148	1.72E-05	2.55E-03	2	1.57E-04	2.35E-04	0	4.87E-03	2.19E-03	
	HHC	90	88	1.72E-05	1.52E-03	1	5.21E-04	4.69E-04	1	4.87E-03	4.38E-03	
Flanges	VAP	23	23	6.83E-07	1.55E-05	0	2.59E-04	5.95E-05	0	6.59E-03	4.55E-04	
	LHC	180	178	6.83E-07	1.21E-04	2	2.59E-04	4.66E-04	1	6.59E-03	3.56E-03	
	HHC	80	78	6.83E-07	5.36E-05	1	8.02E-04	6.42E-04	1	6.59E-03	5.27E-03	
Pumps	LHC	10	5	5.29E-05	2.62E-04	5	4.91E-03	2.43E-02	0	3.05E-02	3.05E-03	
	HHC	5	5	5.29E-05	2.49E-04	0	4.91E-03	2.36E-04	0	3.05E-02	1.47E-03	
Compressors	VAP	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	3.18E-03	0.00E+00	
Subtotal					5.10E-03			2.65E-02			2.07E-02	5.22E-02
TOTAL (lbs/hr)	3.01											
TOTAL (tons/yr)	13.2											

Table III-N-5 Hourly H₂S Emissions from Equipment Leaks

Component	Total Quantity	Default Zero			Leaking @ 500 ppmv			Leaking @ 5,000 ppmv			Total H ₂ S Emission Rate (lb/hr)
		Quantity	Emission Factor (lbH ₂ S/hr/component)	H ₂ S Emission Rate (lb/hr)	Quantity	Emission Factor (lbH ₂ S/hr/component)	H ₂ S Emission Rate (lb/hr)	Quantity	Emission Factor (lbH ₂ S/hr/component)	H ₂ S Emission Rate (lb/hr)	
Unit 13 - Sulfur Recovery Unit											
Valves	1920	960	1.72E-05	4.13E-03	950	5.21E-04	1.24E-01	10	2.90E-03	6.96E-03	
Flanges	1310	655	6.83E-07	1.12E-04	648	8.02E-04	1.30E-01	7	4.05E-03	6.63E-03	
Pumps	12	6	5.29E-05	7.94E-05	6	4.91E-03	7.29E-03	0	2.00E-02	3.00E-04	
Compressors	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	1.95E-03	0.00E+00	
TOTAL				4.32E-03			2.61E-01			1.39E-02	2.79E-01

Table III-N-6 Annual H₂S Emissions from Equipment Leaks

Component	Total Quantity	Default Zero			Leaking @ 500 ppmv			Leaking @ 2,500 ppmv			Total H ₂ S Emission Rate (lb/hr)
		Quantity	Emission Factor (lbH ₂ S/hr/component)	H ₂ S Emission Rate (lb/hr)	Quantity	Emission Factor (lbH ₂ S/hr/component)	H ₂ S Emission Rate (lb/hr)	Quantity	Emission Factor (lbH ₂ S/hr/component)	H ₂ S Emission Rate (lb/hr)	
Unit 13 - Sulfur Recovery Unit											
Valves	1920	960	1.72E-05	4.13E-03	950	5.21E-04	1.24E-01	10	1.73E-03	4.15E-03	
Flanges	1310	655	6.83E-07	1.12E-04	648	8.02E-04	1.30E-01	7	2.49E-03	4.07E-03	
Pumps	12	6	5.29E-05	7.94E-05	6	4.91E-03	7.29E-03	0	1.31E-02	1.97E-04	
Compressors	0	0	8.82E-06	0.00E+00	0	3.85E-04	0.00E+00	0	1.20E-03	0.00E+00	
TOTAL				4.32E-03			2.61E-01			8.42E-03	2.74E-01
TOTAL (tons/yr)	1.22										

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 1 - Atmospheric Distillation						
Valves	VAP	1.30%	7.73E-02	1.41E-02	1.00E-03	1.84E-04
	LHC	1.21%	2.14E-01	3.92E-02	2.59E-03	4.74E-04
	HHC	0.67%	4.56E-01	9.05E-02	3.05E-03	6.07E-04
Flanges	VAP	1.30%	7.38E-02	6.63E-03	9.59E-04	8.62E-05
	LHC	1.21%	2.04E-01	1.84E-02	2.47E-03	2.22E-04
	HHC	0.67%	4.47E-01	6.44E-02	2.99E-03	4.32E-04
Pumps	LHC	1.21%	2.72E-02	2.51E-02	3.29E-04	3.03E-04
	HHC	0.67%	2.94E-02	3.99E-03	1.97E-04	2.68E-05
Compressors	VAP	1.30%	2.53E-04	4.13E-04	3.29E-06	5.37E-06
Subtotal			1.53E+00	2.63E-01	1.36E-02	2.34E-03
Unit 2 - Vacuum Distillation						
Valves	VAP	0.72%	2.04E-02	3.74E-03	1.47E-04	2.69E-05
	LHC	0.15%	1.60E-02	2.93E-03	2.40E-05	4.39E-06
	HHC	0.22%	2.08E-01	4.14E-02	4.58E-04	9.10E-05
Flanges	VAP	0.72%	2.04E-02	1.83E-03	1.47E-04	1.32E-05
	LHC	0.15%	1.60E-02	1.44E-03	2.40E-05	2.15E-06
	HHC	0.22%	2.14E-01	3.08E-02	4.70E-04	6.78E-05
Pumps	LHC	0.15%	2.18E-03	2.01E-03	3.27E-06	3.01E-06
	HHC	0.22%	1.44E-02	1.96E-03	3.18E-05	4.31E-06
Compressors	VAP	0.72%	5.06E-04	8.26E-04	3.64E-06	5.95E-06
Subtotal			5.12E-01	8.69E-02	1.31E-03	2.19E-04

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 3 - Gas Plant						
Valves	VAP	1.30%	2.92E-02	5.34E-03	3.79E-04	6.94E-05
	LHC	1.21%	1.56E-01	2.85E-02	1.89E-03	3.45E-04
	HHC	0.67%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flanges	VAP	1.30%	2.75E-02	2.47E-03	3.58E-04	3.22E-05
	LHC	1.21%	1.47E-01	1.32E-02	1.78E-03	1.60E-04
	HHC	0.67%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pumps	LHC	1.21%	3.98E-02	3.67E-02	4.81E-04	4.44E-04
	HHC	0.67%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	1.30%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			4.00E-01	8.63E-02	4.89E-03	1.05E-03
Unit 4 - Naphtha Hydrotreater						
Valves	VAP	1.34%	6.52E-02	1.19E-02	8.74E-04	1.60E-04
	LHC	1.38%	1.67E-01	3.06E-02	2.31E-03	4.22E-04
	HHC	0.37%	8.30E-02	1.65E-02	3.07E-04	6.11E-05
Flanges	VAP	1.34%	6.15E-02	5.53E-03	8.25E-04	7.41E-05
	LHC	1.38%	1.58E-01	1.42E-02	2.18E-03	1.96E-04
	HHC	0.37%	8.05E-02	1.16E-02	2.98E-04	4.29E-05
Pumps	LHC	1.38%	1.50E-02	1.38E-02	2.07E-04	1.91E-04
	HHC	0.37%	3.79E-03	5.14E-04	1.40E-05	1.90E-06
Compressors	VAP	1.34%	5.06E-04	8.26E-04	6.78E-06	1.11E-05
Subtotal			6.35E-01	1.06E-01	7.02E-03	1.16E-03

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 5 - Catalytic Reformer						
Valves	VAP	2.93%	3.96E-02	7.24E-03	1.16E-03	2.12E-04
	LHC	2.87%	1.39E-01	2.54E-02	3.99E-03	7.30E-04
	HHC	1.67%	7.07E-02	1.40E-02	1.18E-03	2.35E-04
Flanges	VAP	2.93%	3.85E-02	3.46E-03	1.13E-03	1.01E-04
	LHC	2.87%	1.35E-01	1.22E-02	3.89E-03	3.49E-04
	HHC	1.67%	7.06E-02	1.02E-02	1.18E-03	1.70E-04
Pumps	LHC	2.87%	1.49E-02	1.37E-02	4.26E-04	3.93E-04
	HHC	1.67%	3.84E-03	5.21E-04	6.42E-05	8.71E-06
Compressors	VAP	2.93%	7.59E-04	1.24E-03	2.22E-05	3.63E-05
Subtotal			5.13E-01	8.80E-02	1.30E-02	2.24E-03
Unit 6 - Isomerization (Penex)						
Valves	VAP	2.49%	3.20E-02	5.85E-03	7.97E-04	1.46E-04
	LHC	2.49%	1.34E-01	2.45E-02	3.34E-03	6.11E-04
	HHC	0.62%	5.93E-03	1.18E-03	3.68E-05	7.31E-06
Flanges	VAP	2.49%	3.11E-02	2.80E-03	7.76E-04	6.97E-05
	LHC	2.49%	1.30E-01	1.17E-02	3.25E-03	2.92E-04
	HHC	0.62%	5.93E-03	8.55E-04	3.68E-05	5.30E-06
Pumps	LHC	2.49%	2.08E-02	1.92E-02	5.17E-04	4.77E-04
	HHC	0.62%	4.68E-04	6.35E-05	2.90E-06	3.94E-07
Compressors	VAP	2.49%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			3.61E-01	6.62E-02	8.75E-03	1.61E-03

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 7 - Hydrogen Production						
Valves	VAP	0.10%	2.66E-02	4.86E-03	2.66E-05	4.86E-06
	LHC	0.10%	7.85E-03	1.44E-03	7.85E-06	1.44E-06
	HHC	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flanges	VAP	0.10%	2.51E-02	2.25E-03	2.51E-05	2.25E-06
	LHC	0.10%	7.41E-03	6.66E-04	7.41E-06	6.66E-07
	HHC	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pumps	LHC	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	HHC	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			6.69E-02	9.21E-03	6.69E-05	9.21E-06
Unit 8 - Distillate Hydrotreater						
Valves	VAP	1.34%	6.70E-02	1.23E-02	8.98E-04	1.64E-04
	LHC	1.38%	1.68E-01	3.07E-02	2.32E-03	4.24E-04
	HHC	0.37%	2.62E-01	5.21E-02	9.70E-04	1.93E-04
Flanges	VAP	1.34%	6.43E-02	5.77E-03	8.61E-04	7.74E-05
	LHC	1.38%	1.61E-01	1.45E-02	2.22E-03	2.00E-04
	HHC	0.37%	2.58E-01	3.72E-02	9.55E-04	1.38E-04
Pumps	LHC	1.38%	3.67E-02	3.39E-02	5.07E-04	4.67E-04
	HHC	0.37%	2.92E-02	3.96E-03	1.08E-04	1.47E-05
Compressors	VAP	1.34%	2.53E-04	4.13E-04	3.39E-06	5.54E-06
Subtotal			1.05E+00	1.91E-01	8.84E-03	1.68E-03

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 10 - Hydrocracker (Unicracker)						
Valves	VAP	0.78%	6.69E-02	1.22E-02	5.22E-04	9.55E-05
	LHC	1.09%	3.52E-01	6.45E-02	3.84E-03	7.03E-04
	HHC	0.10%	4.51E-01	8.95E-02	4.51E-04	8.95E-05
Flanges	VAP	0.78%	6.52E-02	5.86E-03	5.09E-04	4.57E-05
	LHC	1.09%	3.43E-01	3.09E-02	3.74E-03	3.36E-04
	HHC	0.10%	4.51E-01	6.50E-02	4.51E-04	6.50E-05
Pumps	LHC	1.09%	4.68E-02	4.32E-02	5.10E-04	4.71E-04
	HHC	0.10%	3.05E-02	4.13E-03	3.05E-05	4.13E-06
Compressors	VAP	0.78%	7.59E-04	1.24E-03	5.92E-06	9.67E-06
Subtotal			1.81E+00	3.17E-01	1.01E-02	1.82E-03
Unit 11 - Sour Water Stripping						
Valves	VAP	0.95%	4.41E-04	8.07E-05	4.19E-06	7.66E-07
	LHC	0.95%	2.72E-03	4.97E-04	2.58E-05	4.72E-06
	HHC	0.95%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flanges	VAP	0.95%	3.90E-04	3.51E-05	3.71E-06	3.33E-07
	LHC	0.95%	3.08E-03	2.76E-04	2.92E-05	2.63E-06
	HHC	0.95%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pumps	LHC	0.95%	6.57E-03	6.06E-03	6.24E-05	5.76E-05
	HHC	0.95%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.95%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			1.32E-02	6.95E-03	1.25E-04	6.60E-05

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 12 - Amine Regeneration						
Valves	VAP	0.10%	5.33E-04	9.75E-05	5.33E-07	9.75E-08
	LHC	0.10%	1.79E-03	3.27E-04	1.79E-06	3.27E-07
	HHC	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flanges	VAP	0.10%	5.03E-04	4.52E-05	5.03E-07	4.52E-08
	LHC	0.10%	3.08E-03	2.76E-04	3.08E-06	2.76E-07
	HHC	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pumps	LHC	0.10%	1.20E-02	1.11E-02	1.20E-05	1.11E-05
	HHC	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.10%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			1.79E-02	1.18E-02	1.79E-05	1.18E-05
Unit 14 - Delayed Coker						
Valves	VAP	0.24%	8.88E-02	1.62E-02	2.13E-04	3.90E-05
	LHC	0.85%	1.69E-01	3.09E-02	1.44E-03	2.63E-04
	HHC	0.18%	5.82E-01	1.16E-01	1.05E-03	2.08E-04
Flanges	VAP	0.24%	8.72E-02	7.83E-03	2.09E-04	1.88E-05
	LHC	0.85%	1.66E-01	1.49E-02	1.41E-03	1.27E-04
	HHC	0.18%	5.87E-01	8.46E-02	1.06E-03	1.52E-04
Pumps	LHC	0.85%	3.14E-02	2.90E-02	2.67E-04	2.46E-04
	HHC	0.18%	5.49E-02	7.46E-03	9.89E-05	1.34E-05
Compressors	VAP	0.24%	2.53E-04	4.13E-04	6.07E-07	9.92E-07
Subtotal			1.77E+00	3.07E-01	5.74E-03	1.07E-03

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 15 - Butane Conversion Unit						
Valves	VAP	2.49%	1.05E-01	1.92E-02	2.61E-03	4.77E-04
	LHC	2.49%	3.06E-01	5.60E-02	7.63E-03	1.40E-03
	HHC	0.62%	1.54E-01	3.06E-02	9.53E-04	1.89E-04
Flanges	VAP	2.49%	1.00E-01	8.99E-03	2.49E-03	2.24E-04
	LHC	2.49%	2.93E-01	2.64E-02	7.30E-03	6.56E-04
	HHC	0.62%	1.51E-01	2.18E-02	9.37E-04	1.35E-04
Pumps	LHC	2.49%	3.00E-02	2.76E-02	7.46E-04	6.88E-04
	HHC	0.62%	8.99E-03	1.22E-03	5.57E-05	7.56E-06
Compressors	VAP	2.49%	1.26E-03	2.07E-03	3.15E-05	5.14E-05
Subtotal			1.15E+00	1.94E-01	2.28E-02	3.82E-03
Unit 16 - Benzene Reduction Unit						
Valves	VAP	1.24%	3.20E-02	5.85E-03	3.97E-04	7.26E-05
	LHC	1.24%	1.34E-01	2.45E-02	1.66E-03	3.04E-04
	HHC	1.24%	5.93E-03	1.18E-03	7.35E-05	1.46E-05
Flanges	VAP	1.24%	3.11E-02	2.80E-03	3.86E-04	3.47E-05
	LHC	1.24%	1.30E-01	1.17E-02	1.62E-03	1.45E-04
	HHC	1.24%	5.93E-03	8.55E-04	7.35E-05	1.06E-05
Pumps	LHC	1.24%	2.08E-02	1.92E-02	2.58E-04	2.38E-04
	HHC	1.24%	4.68E-04	6.35E-05	5.80E-06	7.87E-07
Compressors	VAP	1.24%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			3.61E-01	6.62E-02	4.47E-03	8.20E-04

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 26 - Wastewater Treatment Piping						
Valves	VAP	0.0029%	1.15E-02	2.10E-03	3.30E-07	6.04E-08
	LHC	0.0029%	1.15E-02	2.10E-03	3.30E-07	6.04E-08
	HHC	0.0029%	1.65E-01	3.28E-02	4.74E-06	9.43E-07
Flanges	VAP	0.0029%	1.05E-02	9.44E-04	3.02E-07	2.72E-08
	LHC	0.0029%	1.05E-02	9.44E-04	3.02E-07	2.72E-08
	HHC	0.0029%	1.55E-01	2.24E-02	4.46E-06	6.44E-07
Pumps	LHC	0.0029%	1.34E-03	1.24E-03	3.85E-08	3.55E-08
	HHC	0.0029%	9.80E-03	1.33E-03	2.82E-07	3.82E-08
Compressors	VAP	0.0029%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			3.75E-01	6.38E-02	1.08E-05	1.84E-06
Unit 41 - Crude Oil Metering Station						
Valves	VAP	0.45%	1.27E-03	2.32E-04	5.71E-06	1.04E-06
	LHC	0.45%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	HHC	0.45%	2.24E-02	4.46E-03	1.01E-04	2.00E-05
Flanges	VAP	0.45%	1.54E-03	1.38E-04	6.92E-06	6.22E-07
	LHC	0.45%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	HHC	0.45%	2.79E-02	4.03E-03	1.26E-04	1.81E-05
Pumps	LHC	0.45%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	HHC	0.45%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.45%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			5.32E-02	8.85E-03	2.39E-04	3.98E-05

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 42 - Tank Farm Piping						
Valves	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.90%	4.42E-01	8.09E-02	3.98E-03	7.28E-04
	HHC	0.008%	7.11E-01	1.41E-01	5.68E-05	1.13E-05
Flanges	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.90%	4.75E-01	4.26E-02	4.27E-03	3.84E-04
	HHC	0.008%	7.83E-01	1.13E-01	6.27E-05	9.04E-06
Pumps	LHC	0.90%	1.44E-01	1.33E-01	1.30E-03	1.20E-03
	HHC	0.008%	1.18E-01	1.60E-02	9.43E-06	1.28E-06
Compressors	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			2.67E+00	5.27E-01	9.67E-03	2.33E-03
Unit 43 - Slop and Flushing Oil Systems						
Valves	VAP	0.95%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.95%	8.32E-02	1.52E-02	7.90E-04	1.45E-04
	HHC	0.95%	4.23E-01	8.41E-02	4.02E-03	7.99E-04
Flanges	VAP	0.95%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.95%	8.93E-02	8.03E-03	8.49E-04	7.62E-05
	HHC	0.95%	4.67E-01	6.73E-02	4.43E-03	6.39E-04
Pumps	LHC	0.95%	9.48E-03	8.75E-03	9.01E-05	8.31E-05
	HHC	0.95%	2.46E-02	3.33E-03	2.33E-04	3.17E-05
Compressors	VAP	0.95%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			1.10E+00	1.87E-01	1.04E-02	1.77E-03

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 44 - Vapor Recovery System Pipework						
Valves	VAP	0.90%	3.58E-02	6.55E-03	3.22E-04	5.90E-05
	LHC	0.90%	3.23E-02	5.92E-03	2.91E-04	5.32E-05
	HHC	0.008%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flanges	VAP	0.90%	3.62E-02	3.25E-03	3.26E-04	2.93E-05
	LHC	0.90%	3.27E-02	2.94E-03	2.94E-04	2.64E-05
	HHC	0.008%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pumps	LHC	0.90%	2.29E-02	2.11E-02	2.06E-04	1.90E-04
	HHC	0.008%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			1.60E-01	3.98E-02	1.44E-03	3.58E-04
Unit 45 - Gasoline Blending Pipework						
Valves	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.90%	9.06E-03	1.66E-03	8.15E-05	1.49E-05
	HHC	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flanges	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.90%	3.85E-02	3.46E-03	3.46E-04	3.11E-05
	HHC	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pumps	LHC	0.90%	7.49E-02	6.91E-02	6.74E-04	6.22E-04
	HHC	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			1.22E-01	7.42E-02	1.10E-03	6.68E-04

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 46 - Rail Loading/Unloading Pipework						
Valves	VAP	0.90%	9.42E-02	1.72E-02	8.48E-04	1.55E-04
	LHC	0.90%	3.08E-01	5.63E-02	2.77E-03	5.07E-04
	HHC	0.008%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flanges	VAP	0.90%	1.56E-01	1.40E-02	1.40E-03	1.26E-04
	LHC	0.90%	5.09E-01	4.57E-02	4.58E-03	4.11E-04
	HHC	0.008%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pumps	LHC	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	HHC	0.008%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			1.07E+00	1.33E-01	9.60E-03	1.20E-03
Unit 47 - Truck Loading/Unloading Pipework						
Valves	VAP	0.90%	6.16E-02	1.13E-02	5.54E-04	1.01E-04
	LHC	0.90%	2.35E-01	4.31E-02	2.12E-03	3.88E-04
	HHC	0.008%	1.42E-02	2.83E-03	1.14E-06	2.26E-07
Flanges	VAP	0.90%	9.81E-02	8.81E-03	8.83E-04	7.93E-05
	LHC	0.90%	3.75E-01	3.37E-02	3.38E-03	3.03E-04
	HHC	0.008%	2.33E-02	3.36E-03	1.86E-06	2.69E-07
Pumps	LHC	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	HHC	0.008%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compressors	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			8.08E-01	1.03E-01	6.93E-03	8.72E-04

Table III-N-7. Benzene Emissions from Equipment Leaks

Component	Service	Benzene Concentration (weight %)	VOC Emission Rates		Benzene Emission Rates	
			Hourly (lb/hr)	Annual (lb/hr)	Hourly (lb/hr)	Annual (lb/hr)
Unit 51 - Closed Drain System Pipework						
Valves	VAP	0.0029%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.0029%	1.38E-02	2.52E-03	3.96E-07	7.25E-08
	HHC	0.0029%	1.42E-02	2.83E-03	4.10E-07	8.14E-08
Flanges	VAP	0.0029%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	LHC	0.0029%	2.23E-02	2.00E-03	6.41E-07	5.76E-08
	HHC	0.0029%	2.37E-02	3.41E-03	6.80E-07	9.81E-08
Pumps	LHC	0.0029%	1.14E-02	1.05E-02	3.27E-07	3.02E-07
	HHC	0.0029%	5.99E-03	8.13E-04	1.72E-07	2.34E-08
Compressors	VAP	0.0029%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			9.13E-02	2.21E-02	2.63E-06	6.35E-07
Unit 60 - Product Pipeline						
Valves	VAP	0.90%	3.62E-03	6.63E-04	3.26E-05	5.96E-06
	LHC	0.90%	2.72E-02	4.97E-03	2.45E-04	4.47E-05
	HHC	0.008%	3.20E-02	6.36E-03	2.56E-06	5.09E-07
Flanges	VAP	0.90%	5.90E-03	5.30E-04	5.31E-05	4.77E-06
	LHC	0.90%	4.62E-02	4.15E-03	4.15E-04	3.73E-05
	HHC	0.008%	4.14E-02	5.97E-03	3.31E-06	4.78E-07
Pumps	LHC	0.90%	3.00E-02	2.76E-02	2.70E-04	2.49E-04
	HHC	0.008%	1.44E-02	1.95E-03	1.15E-06	1.56E-07
Compressors	VAP	0.90%	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Subtotal			2.01E-01	5.22E-02	1.02E-03	3.43E-04
TOTAL			1.68E+01	3.01E+00	1.41E-01	2.55E-02
TOTAL (tons/yr)			1.32E+01		1.12E-01	

Table III-N-8. Organic HAP Emissions from Equipment Leaks

VOC Emission Rate		Ethylbenzene			Hexane			Toluene			Xylenes (total)		
lb/hr	tons/yr	% by weight	lb/hr	tons/yr	% by weight	lb/hr	tons/yr	% by weight	lb/hr	tons/yr	% by weight	lb/hr	tons/yr
16.8	13.2	0.22	0.04	0.03	4.78	0.80	0.63	2.11	0.35	0.28	0.76	0.13	0.10

O. Internal Combustion Engine

Hourly and annual emissions from each of the three internal combustion engines at the proposed refinery are presented in Table III-O. Emissions of all pollutants from internal combustion engines were calculated using heat input capacity and emission factors in much the same manner described for emissions from process heaters in Section III.B, above.

Each internal combustion engine is subject to a fuel use restriction that limits its operation to the equivalent of 200 hours per year, based on equivalent full-load operation. Thus, annual emissions are calculated assuming the hourly emission rate for 200 hours per year.

Emission factors used to calculate emissions from internal combustion engines are shown in Table III-O and were derived as follows:

- For SO₂, the emission factor is derived from Section 3.4 of AP-42, using the maximum allowable fuel sulfur level of 15 parts per million by weight.
- For CO and PM, the permitted emission limits are expressed in units of grams per kilowatt-hour (g/kWh) of power output. These emission factors are converted to units of pounds per horsepower-hour (lb/hp-hr) according to Section 3.4 of AP-42.
- For VOC, the emission factor is taken from Section 3.4 of AP-42.
- For NO_x and VOC, the permitted emission limits are expressed as combined limits on NO_x and nonmethane hydrocarbons (“NO_x + NMHC”) in units of g/kWh. For the purpose of calculating NO_x emissions, it is assumed that zero VOC is emitted, i.e., that the NO_x emission rate from each engine is equal to the allowable NO_x + NMHC emission limit. This emission factor is converted to units of pounds per horsepower-hour (lb/hp-hr) according to Section 3.4 of AP-42.

Table III-O. Internal Combustion Engine Emissions

Emission Unit	Capacity		NO _x			SO ₂			CO			VOC			PM		
	MMBtu/hr	hp	lb/ hp-hr	lb/hr	ton/year	lb/ MMBtu	lb/hr	ton/year	lb/hp- hr	lb/hr	ton/year	lb/hp- hr	lb/hr	ton/year	lb/hp-hr	lb/hr	ton/year
Fire Water Pump Engine #1	5.46	750	0.0066	4.93	0.49	0.0015	0.008	0.0008	0.0058	4.32	0.43	0.0007	0.53	0.05	0.00033	0.25	0.025
Fire Water Pump Engine #2	5.46	750	0.0066	4.93	0.49	0.0015	0.008	0.0008	0.0058	4.32	0.43	0.0007	0.53	0.05	0.00033	0.25	0.025
Emergency Generator Engine	10.9	1500	0.011	15.8	1.58	0.0015	0.017	0.0017	0.0058	8.63	0.86	0.0007	1.06	0.11	0.00033	0.49	0.049
TOTAL				25.7	2.57		0.033	0.0033		17.3	1.73		2.12	0.21		0.99	0.099

P. Vehicle Traffic on Paved Areas

Particulate matter emissions will occur at the proposed refinery as a result of vehicle traffic on paved surfaces. This traffic will primarily consist of tank trucks (i.e., cargo tanks) used to transport the refinery’s products from the refinery site. These emissions are calculated using the predictive emission factor equation from AP-42 Section 13.2.1. This equation is as follows:

$$E = k \times \left(\frac{sL}{2}\right)^{0.65} \times \left(\frac{W}{3}\right)^{1.5} \times VMT$$

Where:

- E = particulate emissions, lbs;
- k = particle size multiplier, 0.016 lb/VMT for PM₁₀ or 0.082 for PM;
- sL = paved surface surface silt loading, g/m²;
- W = average vehicle weight, tons; and
- VMT = vehicle miles traveled, miles.

For the paved area that will be traveled by delivery trucks at the proposed refinery, unlike many industrial sources, there are no dust-generating operations that would be expected to cause a silt loading higher than typically encountered on paved public roads. For this reason, the Department has elected to use the silt loading values provided by AP-42 Section 13.2.1 for public paved roads. Although the number of trucks traveling the paved area at the proposed refinery will be substantial, it is not sufficient to qualify the area for the lower silt loading values for “high average daily traffic” public paved roads as provided in AP-42 Section 13.2.1. Therefore, the Department has elected to use a silt loading value of 0.4 g/m², which is the value provided in AP-42 Section 13.2.1 for “low average daily traffic” public paved roads. The Department considers this value to be a conservatively high estimate, as AP-42 Section 13.2.1 indicates that the data set used to develop this value “is biased high for ‘normal’ situations.”

According to information provided by the applicant, each cargo tank will carry approximately 8,400 gallons of product. Assuming a liquid density of 6.3 pounds per gallon, the cargo will weigh approximately 26 tons. Assuming an empty weight of 14 tons and a loaded weight of 40 tons, the average vehicle weight will be approximately 27 tons.

For the purpose of calculating short-term and long-term particulate matter emissions, the Department calculated the vehicle miles traveled (VMT) to be 107 miles per day and 19,600 miles per year, respectively. Each of these values is based on a round-trip distance of 0.19 miles (equal to 1,000 feet, representing two traverses of a 500-foot distance) for each truck trip. For the purpose of

calculating annual particulate matter emissions, the number of truck trips was based upon a daily average throughput of 2.4 million gallons of product shipped from the refinery by truck. Assuming 8,400 gallons of cargo per truck, the Department determine that there would be approximately 103,000 truck trips per year. For the purpose of calculating short-term particulate matter emissions, the Department determined that there could be as many as 566 truck trips per day, based on a daily throughput of 4.8 million gallons of product shipped from the refinery by truck. Because most of the refinery's product is expected to be shipped via pipeline, the Department considers both of these values to be conservatively high.

Hourly and annual PM and PM₁₀ emissions are presented in Table III-P. These emission rates are calculated as follows, using the annual PM₁₀ emission rate calculation to illustrate:

$$E_{PM_{10}} = \left(0.016 \frac{\text{lb}}{\text{mile}} \right) \times \left(\frac{0.4}{2} \right)^{0.65} \times \left(\frac{27}{3} \right)^{1.5} \times \left(19,600 \frac{\text{miles}}{\text{yr}} \right) \times \left(\frac{1 \text{ ton}}{2,000 \text{ lb}} \right) = 1.50 \frac{\text{tons}}{\text{yr}}$$

Table III-P. Particulate Matter Emissions from Vehicle Traffic on Paved Areas

Emission Unit	PM		PM ₁₀	
	Hourly	Annual	Hourly	Annual
Particle size multiplier, <i>k</i> (lb/VMT)	0.082	0.082	0.016	0.016
Silt loading, <i>sL</i> (g/m ²)	0.4	0.4	0.4	0.4
Average vehicle weight (tons)	27	27	27	27
Vehicle miles traveled, <i>VMT</i> (miles)	4.5	19,600	4.5	19,600
Emissions (lb/hr or tons/yr)	3.52	7.71	0.69	1.50

IV. REGULATORY APPLICABILITY

The Permittee has identified all applicable regulations that apply to each unit identified in the permit application. Sections IV.A through IV.G of this document present a detailed explanation of the rationale for applicability and non-applicability for certain regulations.

A. Permit Regulations

1. Class I Permit

a. Applicability

The potentially applicable air quality permit regulations are the State of Arizona regulations at Title 18, Chapter 2, Articles 3 and 4.

b. Permit Application Processing

Pursuant to Arizona Administrative Code (A.A.C.) R18-2-302.A and -302.B, a Class I permit is required prior to construction or operation of a major source. The proposed refinery has the potential to emit more than 25 tons per year of hazardous air pollutants and, therefore, would be a major source under Section 112 of the Clean Air Act. (See A.A.C. R18-2-101.64.b.i.) The proposed refinery also has the potential to emit more than 100 tons per year of several regulated air pollutants and is in a listed source category and, therefore, is a major stationary source under Section 302 of the Clean Air Act. (See A.A.C. R18-2-101.64.c.)

2. Nonattainment New Source Review

The site of the proposed refinery is in an area that is in attainment or is unclassifiable for all pollutants. (In other words, the area is not a nonattainment area for any pollutant.) Therefore, the proposed refinery is not a major source pursuant to A.A.C. R18-2-401.9.a and is not subject to the provisions of A.A.C. R18-2-403 through 405.

3. Prevention of Significant Deterioration

a. Applicability

The proposed refinery has the potential to emit more than 100 tons per year of several air pollutants and is a categorical source pursuant to A.A.C. R18-2-401.2. The site of the proposed refinery is in an area that is in attainment or is unclassifiable for all pollutants. (In other words, the area is not a nonattainment area for

any pollutant.) Therefore, the proposed refinery is a major source pursuant to A.A.C. R18-2-401.9.b and is subject to the provisions of R18-2-406. The pollutants for which the proposed refinery's potential to emit is significant are carbon monoxide, nitrogen oxides, sulfur dioxide, particulate matter, PM₁₀, volatile organic compounds, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.

b. Best Available Control Technology

Pursuant to A.A.C. R18-2-406.A, the proposed refinery is required to apply Best Available Control Technology (BACT) for each pollutant for which the potential to emit is significant. The determination of BACT is discussed in detail in Section V herein.

c. Air Quality Impact Analysis and Monitoring Requirements

Pursuant to A.A.C. R18-2-407, the Permittee is required to perform an analysis of the air quality impacts of the proposed refinery. The air quality impact analysis is discussed in detail in Section VII herein.

d. Visibility Impact Analysis

Pursuant to A.A.C. R18-2-410, the Permittee is required to perform an analysis of the visibility impacts of the proposed refinery. The visibility impact analysis is discussed in detail in Section VII herein.

B. New Source Performance Standards (NSPS)

The NSPS regulations apply to listed types of emission units and process units (i.e., "affected facilities") for which construction, reconstruction, or modification is commenced after a particular date, specific to that unit or source type. Several of these NSPS regulations are applicable to one or more emission units and process units at the proposed refinery.

1. 40 CFR 60 Subpart A, General Provisions

The provisions of subpart A apply to each affected facility, as specified in the relevant NSPS regulation for that source type. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions. In addition, § 60.18 of subpart A contains requirements for flares used to comply with other NSPS regulations. The proposed refinery includes two emergency flares subject to these requirements.

Subpart A of 40 CFR part 60 is adopted by reference at A.A.C. R18-2-901.1.

2. 40 CFR 60 Subpart D, Fossil-Fuel-Fired Steam Generators

Subpart D is superseded by subpart Db for affected steam generating units constructed after June 19, 1984.

3. 40 CFR 60 Subpart Da, Electric Utility Steam Generating Units

Subpart Da applies to steam generating units that supply electrical output to a utility power distribution system. The proposed refinery will not include any steam generating units meeting this criterion.

4. 40 CFR 60 Subpart Db, Industrial-Commercial-Institutional Steam Generating Units

Subpart Db applies to each steam generating unit with a heat input capacity of 100 million British Thermal Units per hour (MMBtu/hr) or greater. The proposed refinery includes two steam boilers subject to this regulation. Other combustion devices at the refinery do not combust fuels for the purpose of producing steam, or heating water or any other heat transfer medium. Other than the steam boilers, each of the combustion devices at the refinery is a process heater, as that term is defined at 40 CFR 60.41b, and is specifically excluded from applicability of subpart Db.

The provisions of subpart Db include emission standards for particulate matter (PM), SO₂, and nitrogen oxides (NO_x), as well as monitoring, recordkeeping, performance testing, and reporting requirements. The two steam boilers at the proposed refinery will be subject only to the NO_x emission standards under subpart Db. The regulation does not include any PM or SO₂ emission standards for units firing exclusively natural gas. The applicable provisions of subpart Db are included in Section XXVI of the proposed permit.

Subpart Db is adopted by reference at A.A.C. R18-2-901.4.

5. 40 CFR 60 Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc applies to each steam generating unit having a heat input capacity between 10 MMBtu/hr and 100 MMBtu/hr. The proposed refinery will not include any steam generating units in this size range. The two steam boilers, as discussed in Section IV.B.4 herein, will have heat input capacities in excess of 100 MMBtu/hr. Other than the two steam

boilers, each of the combustion devices at the refinery is a process heater, as that term is defined at 40 CFR 60.41c, and is specifically excluded from applicability of subpart Dc.

6. 40 CFR 60 Subpart J, Petroleum Refineries

Subpart J applies to each fluid catalytic cracking unit catalyst regenerator, each sulfur recovery plant, and each fuel gas combustion device at a petroleum refinery. The proposed refinery will include one sulfur recovery unit and numerous fuel gas combustion devices, but will not include a fluid catalytic cracking unit. (The Hydrocracker Unit serves a similar function to a typical fluid catalytic cracking unit, but uses a fixed reactor bed rather than a fluidized bed. The Catalytic Reforming Unit and the Butane Conversion Unit each includes a catalyst regenerator, but these units are not subject to the provisions of subpart J because they are not associated with fluid catalytic cracking units.)

The proposed refinery will include one sulfur recovery plant comprising two parallel sulfur recovery units. (The United States Environmental Protection Agency (U.S. EPA) has interpreted the term “Claus sulfur recovery plant” in subpart J to include multiple sulfur recovery units fed by a common acid gas header.) The provisions of subpart J that are applicable to the sulfur recovery plant include an SO₂ emission limitation and monitoring, recordkeeping, performance testing, and reporting requirements. These provisions are included in Section XIV of the proposed permit.

The fuel gas combustion devices at the proposed refinery include process heaters and thermal oxidizers. (The U.S. EPA has interpreted the term “fuel gas” in subpart J broadly, to include such gas streams as the vapors captured by wastewater treatment vessels, storage vessel closed vent systems, and gasoline loading rack vapor collection systems.) The provisions of subpart J to which the fuel gas combustion devices are subject include a limitation on fuel gas hydrogen sulfide concentration and monitoring, recordkeeping, performance testing, and reporting requirements. These provisions are included in Sections I, III, IV, V, VII, VIII, X, XII, XV, XVII, XXI, and XXIII of the proposed permit.

Subpart J is adopted by reference at A.A.C. R18-2-901.14.

7. 40 CFR 60 Subpart Kb, Volatile Organic Liquid Storage Vessels

Subpart Kb applies to each storage vessel that is used to store volatile organic liquids and has a capacity of 40 cubic meters or more. The provisions of subpart Kb include requirements for control equipment design, operation, and maintenance, as well as recordkeeping and

reporting requirements. For each storage vessel having a capacity less than the threshold values specified in the regulation, and storing liquids having vapor pressures less than the corresponding threshold values specified in the regulation, only the recordkeeping requirements apply.

The proposed refinery will include numerous storage tanks meeting these criteria. Most of these are Group 1 storage vessels under subpart CC of 40 CFR part 63. Pursuant to § 63.640(n)(2) of subpart CC, Group 1 storage vessels are not required to comply with the provisions of subpart Kb.

The rich amine and lean amine storage tanks in the Amine Regeneration Unit, the MDEA storage tank in the Sulfur Recovery Plant, and a single asphalt storage tank (T-42801) store liquids with vapor pressures below the thresholds for control requirements under § 60.110b(c) of subpart Kb. These tanks are classified as Group 2 storage vessels under subpart CC of 40 CFR part 63. Pursuant to § 63.640(n)(4) of subpart CC, Group 2 storage vessels that would not require control under subpart Kb are not required to comply with the provisions of subpart Kb.

The only tank at the proposed refinery that is required to comply with the provisions of subpart Kb is the Sour Water Tank. This tank will be used to store liquids with a maximum true vapor pressure less than 76.6 kilopascals (kPa). Compliance will be achieved using a fixed roof in combination with an internal floating roof. The applicable provisions of subpart Kb are included in Section XIII of the proposed permit.

It is worth noting that, in addition to the storage tanks discussed above, the proposed refinery will include four tanks in the Wastewater Treatment Plant. These tanks are “flow-through” tanks that, under current U.S. EPA policy, are not “used for the storage of volatile organic liquids” and are not storage vessels subject to the provisions of subpart Kb.

Subpart Kb is adopted by reference at A.A.C. R18-2-901.17.

8. 40 CFR 60 Subpart UU, Asphalt Processing

Subpart UU applies to each asphalt storage tank at a petroleum refinery. The proposed refinery will include one asphalt storage tank subject to the provisions of subpart UU. The applicable provisions of subpart UU, including an opacity limitation and a performance test requirement, are included in Section XX of the proposed permit.

Subpart UU is adopted by reference at A.A.C. R18-2-901.51.

9. 40 CFR 60 Subpart VV, Synthetic Organic Chemicals Manufacturing Industry (SOCMI) Equipment Leaks

Subpart VV applies to process units that produce, as an intermediate final product, any of the synthetic organic chemicals listed at § 60.489 of subpart VV. According to the permit application submitted by the Permittee, none of the chemicals included in that list will be produced by any of the process units at the proposed refinery. Further, pursuant to § 63.640(p) of subpart CC of 40 CFR part 63, because each process unit at the proposed refinery will be subject to the provisions of subpart CC, compliance with subpart VV would not be required even if one of the listed chemicals were produced at the proposed refinery.

10. 40 CFR 60 Subpart XX, Bulk Gasoline Terminals

Subpart XX applies to loading racks at bulk gasoline terminals, including those that are collocated with petroleum refineries. Pursuant to § 63.640(r) of subpart CC of 40 CFR part 63, because each gasoline loading rack at the proposed refinery will be subject to the provisions of subpart CC, compliance with the provisions of subpart XX is not required.

11. 40 CFR 60 Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries

Subpart GGG applies to petroleum refinery process units and includes requirements relating to equipment leaks. Pursuant to § 63.640(p) of subpart CC of 40 CFR part 63, because each process unit at the proposed refinery will be subject to the provisions of subpart CC, compliance with the provisions of subpart GGG is not required.

12. 40 CFR 60 Subpart NNN, VOC Emissions from SOCFI Distillation Operations

Subpart NNN applies to distillation units that are part of a process unit that produces, as a product, co-product, by-product, or intermediate, any of the synthetic organic chemicals listed at § 60.667 of subpart NNN.

Two process units at the proposed refinery will produce propane and butane, both of which are listed chemicals. These process units contain a total of five distillation units. The Gas Concentration Plant includes Deethanizer, Depropanizer, and Debutanizer Columns and the Butane Conversion Unit includes Splitter and Stabilizer Columns. The provisions of subpart NNN that are applicable to these distillation units, as described below, are included in Sections II and VIII of the proposed permit.

Based on information provided by the Permittee, there will be a total of two vent streams from the five affected distillation units (one from each affected process unit). Compliance with § 60.662(a) of subpart NNN will

be achieved for these two vent streams by routing them to the RFG system and combusting the RFG in enclosed combustion devices. Other requirements of subpart NNN include monitoring, recordkeeping and reporting provisions. The monitoring provisions at § 60.663(a) and (c) of subpart NNN include firebox temperature monitoring for every combustion device used to combust affected distillation unit vent streams. The Permittee has indicated that it will request from the U.S. EPA Administrator approval of an alternative monitoring plan, as many other petroleum refineries have done for vent streams subject to subpart NNN.

Other process units at the proposed refinery do not produce listed synthetic organic chemicals and, therefore, are not subject to the provisions of subpart NNN.

Subpart NNN is adopted by reference at A.A.C. R18-2-901.65.

13. 40 CFR 60 Subpart QQQ, VOC Emissions from Petroleum Refinery Wastewater Systems

Subpart QQQ applies to wastewater treatment facilities at petroleum refineries.

The Permittee has committed to treat all wastewater streams at the proposed refinery as Group 1 wastewater streams, pursuant to subpart CC of 40 CFR part 63. Pursuant to § 63.640(o) of subpart CC, wastewater treatment facilities that are used to treat Group 1 wastewater streams are not required to comply with the provisions of subpart QQQ.

14. 40 CFR 60 Subpart RRR, VOC Emissions from SOCMR Reactor Processes

Subpart RRR applies to reactor processes that are part of a process unit that produces, as a product, co-product, by-product, or intermediate, any of the synthetic organic chemicals listed at § 60.707 of subpart RRR.

Two process units at the proposed refinery will produce propane and butane, both of which are listed chemicals. One of these, the Gas Concentration Plant, does not include any reactor processes. The other, the Butane Conversion Unit, includes three reactor processes. The provisions of subpart RRR that are applicable to the Butane Conversion Unit reactor processes, as described below, are included in Section VIII of the proposed permit.

Based on information provided by the Permittee, there will be one vent stream from the Butane Conversion Unit reactor processes. Compliance with § 60.702(a) of subpart RRR will be achieved for this vent stream by

routing it to the RFG system and combusting the RFG in enclosed combustion devices. Other requirements of subpart RRR include monitoring, recordkeeping and reporting provisions.

Other process units at the proposed refinery do not produce listed synthetic organic chemicals and, therefore, are not subject to the provisions of subpart RRR.

Subpart RRR is adopted by reference at A.A.C. R18-2-901.69.

C. National Emission Standards for Hazardous Air Pollutants (NESHAP)

1. 40 CFR 61 Subpart A, General Provisions

The provisions of subpart A apply to each affected facility, as specified in the relevant NESHAP regulation for that source type. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions.

Subpart A of 40 CFR part 61 is adopted by reference at A.A.C. R18-2-1101.A.1.

2. 40 CFR 61 Subpart FF, Benzene Waste Operations

Subpart FF includes requirements for reducing the quantity of benzene in facility waste and for the design and operation of equipment used to handle or treat benzene-containing wastes. The specific requirements for a particular facility depend on the uncontrolled quantity of benzene in facility waste. Facilities with less than 10 metric tons of benzene waste per year can perform recordkeeping to document that fact and are then subject to substantially less stringent control requirements.

The applicable provisions of subpart FF are included in Section XXIII of the proposed permit. Several provisions of subpart FF have been streamlined out of the permit, and several other provisions have been enhanced in the proposed permit terms in order to reflect both the subpart FF requirements and other, more stringent requirements. These are as follows:

- Under the Prevention of Significant Deterioration (PSD) BACT requirements (see Section V herein), the proposed refinery will include controls that are at least equivalent to the control requirements under subpart FF. As a result, the Permittee has indicated to the Department that it will comply with the provisions for larger facilities. Therefore, the requirements for smaller facilities have been streamlined out of the permit.

- One of the compliance options for benzene waste treatment available at § 61.348(a)(1) of subpart FF involves incineration, but the Permittee has not requested permission to install a waste incinerator as part of the proposed refinery, so the requirements pertaining to waste incinerators have been streamlined out of the permit.
- The Permittee has proposed as BACT the use of closed-vent systems and control devices for all waste management and treatment operations, so the regulatory requirements for floating-roof tanks have been streamlined out of the permit.
- The Permittee has not requested permission to construct any surface impoundments, so the regulatory requirements for surface impoundments have been streamlined out of the permit.
- The Permittee has proposed as BACT the use of dual carbon canisters to control emissions from individual drain systems that are not vented to enclosed combustion devices. This is more stringent than the requirement for single carbon canisters at § 61.349(a)(2)(ii), and the permit requirements for monitoring and recordkeeping for these control devices have been enhanced accordingly.
- Other than the dual carbon canisters approved for use on certain individual drain systems, the only control devices approved for use in complying with subpart FF are the Tank Farm Thermal Oxidizer (if any non-aqueous waste streams should be stored in a “Group B” storage tank) and the Wastewater Treatment Plant Thermal Oxidizer. One of the compliance options for these control devices, pursuant to § 61.349(a)(2)(i)(C) of subpart FF, is a requirement to meet a specified minimum combustion zone temperature and a specified minimum combustion zone residence time. The PSD BACT requirements for these control devices are more stringent and are expressed in similar terms, so the operational requirements under subpart FF have been streamlined out of the permit.

Subpart FF is adopted by reference at A.A.C. R18-2-1101.A.15.

3. 40 CFR 63 Subpart A, General Provisions

The provisions of subpart A apply to each affected facility, as specified in the relevant NESHAP regulation for that source type. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions.

Subpart A of 40 CFR part 63 is adopted by reference at A.A.C. R18-2-1101.B.1.

4. 40 CFR 63 Subpart B, Control Technology Determinations for Major Sources in Accordance with Clean Air Act §§ 112(g) and 112(j)

Most of the regulations in 40 CFR part 63, including subpart F through subpart DDDDD discussed below, are source category-specific NESHAP regulations implementing Clean Air Act § 112(d). Each of these source category-specific NESHAP includes the U.S. EPA's determination of the Maximum Achievable Control Technology (MACT) for the specified source category.

For emission units that are located at major sources of HAPs and that are not subject to a source category-specific NESHAP, Clean Air Act §§ 112(g) and 112(j) generally require case-by-case determinations of MACT. These requirements are implemented through the provisions of subpart B of 40 CFR part 63. Subpart B is adopted by reference at A.A.C. R18-2-1101.B.2.

There are two separate and distinct sets of requirements in subpart B. The first, at §§ 63.40 through 63.44, implements § 112(g) of the Clean Air Act. Case-by-case MACT determinations pursuant to §§ 63.40 through 63.44 are required by A.A.C. R18-2-302.D. These provisions apply to construction or reconstruction of major sources of HAPs at which there are HAP-emitting units that have neither been regulated nor exempted from regulation under a source category-specific NESHAP.

For the proposed refinery, all HAP-emitting units are exempt from the provisions of §§ 63.40 through 63.44 because they either are regulated or are specifically exempted from regulation under a source category-specific NESHAP.

The second set of provisions, at §§ 63.50 through 63.56 of subpart B, implements § 112(j) of the Clean Air Act. These provisions apply to major sources of HAPs in source categories for which the U.S. EPA has failed to promulgate a source category-specific NESHAP within 18 months after the scheduled promulgation date for that regulation. These provisions are not applicable to any emissions units at the proposed refinery.

5. 40 CFR 63 Subparts F and G, SOCFI Process Units

Subparts F and G apply to chemical manufacturing process units that manufacture, as a primary product, any of the synthetic organic chemicals listed in Table 1 of subpart F. None of the process units at the proposed

refinery will produce as its primary product any of the listed chemicals. Therefore, none of the process units at the proposed refinery is subject to subparts F or G. However, specific requirements for storage vessels under subpart G are applicable to certain storage tanks at the proposed refinery pursuant to § 63.646(a) of subpart CC of 40 CFR part 63.

6. 40 CFR 63 Subpart H, Equipment Leaks

Subpart H applies to pumps, compressors, agitators, pressure relief devices, sampling connection systems, valves, connectors, and instrumentation systems. This regulation is applicable to specific categories of sources where other applicable NESHAP regulations reference its requirements. It is applicable to the proposed refinery pursuant to § 63.648(a) of subpart CC of 40 CFR part 63.

The requirements of subpart H include prescribed procedures and frequencies for leak detection and repair as well as associated recordkeeping and reporting provisions. Under the PSD BACT requirements (see Section V herein), the Permittee has committed to use a lower leak definition than is required by subpart H, which has the effect of making the leak detection and repair provisions more stringent. The applicable provisions of subpart H are included in Section XXIV of the proposed permit.

Subpart H is adopted by reference at A.A.C. R18-2-1101.B.6.

7. 40 CFR 63 Subpart R, Gasoline Distribution Facilities

Subpart R applies to bulk gasoline terminals, but exempts gasoline terminals that are contiguous with a petroleum refinery and that operate under Standard Industrial Classification code 2911 (facilities with petroleum refining as their primary business activity). The gasoline loading racks at the proposed refinery meet this exemption and, therefore, are not affected sources to which subpart R is applicable. Compliance with several provisions of subpart R is required for the proposed refinery's gasoline loading racks, however, pursuant to subpart CC of 40 CFR part 63, as discussed below.

8. 40 CFR 63 Subpart CC, Petroleum Refineries

Subpart CC is a far-reaching regulation that imposes HAP emission standards for various refinery operations, including storage vessels, equipment leaks, wastewater streams, gasoline loading racks, process vents, and marine tank vessel loading operations. Many of the emission units at the proposed refinery are subject to these emission standards.

With the exception of the four tanks used in the Wastewater Treatment Plant and the six pressurized Group “D” storage tanks, all of the tanks at the proposed refinery are subject to the storage vessel provisions of subpart CC. (These types of tanks are specifically excluded from the definition of *storage vessel* at § 63.641 of subpart CC.) The rich amine and lean amine storage tanks in the Amine Regeneration Unit and the MDEA storage tank in the Sulfur Recovery Plant will store low-vapor-pressure products and are classified as Group 2 storage vessels under subpart CC. These provisions of subpart CC that are applicable to these storage tanks include recordkeeping and reporting requirements. These requirements are included in Sections XII and XIV of the proposed permit.

The remaining 51 storage tanks at the proposed refinery are classified as Group 1 storage vessels and are subject to the control requirements under subpart CC. The control requirements for these Group 1 storage vessels are the requirements set forth at § 63.119 of subpart G of 40 CFR part 63, pursuant to § 63.646(a) of subpart CC. Several compliance options are available, including the use of an external floating roof, a fixed roof with an internal floating roof, or a closed-vent system and control device. The 51 storage tanks at the proposed refinery are grouped, for the purposes of the draft air quality permit, by the control option selected.

The eight Group “A” storage tanks will comply with § 63.119(e) of subpart G, which requires that the control device maintain at least 95 percent control of organic HAP emissions. These tanks will be equipped with closed-vent systems vented to a compression system, which in turn routes the compressed vapors to the RFG system. This system meets the PSD BACT requirements and will achieve substantially greater than 95 percent control efficiency. Additional requirements under subpart G include an engineering design evaluation to demonstrate initial compliance, recordkeeping, and reporting provisions. The provisions of subpart CC (and, by reference, subpart G) that are applicable to the Group “A” storage tanks are included in Section XVI of the proposed permit.

The forty-seven Group “B” storage tanks will also comply with § 63.119(e) of subpart G. Each of these tanks will be equipped with an internal floating roof, a fixed roof, and a closed-vent system vented to the Tank Farm Thermal Oxidizer. This configuration satisfies the PSD BACT requirements and will achieve substantially greater than 95 percent control efficiency, which is required by § 63.119(e). Additional requirements under subpart G include an engineering design evaluation to demonstrate initial compliance, recordkeeping, and reporting provisions. The provisions of subpart CC (and, by reference, subpart G) that are applicable to the Group “B” storage tanks are included in Section XVII of the proposed permit. It should be noted that the requirements under §

63.119(b) of subpart G, relating to internal floating roofs, are not applicable to the Group “B” storage tanks because the applicant has chosen to comply with the § 63.119(e) compliance option.

Equipment leaks at the proposed refinery will be subject to the leak detection and repair program requirements in subpart H of 40 CFR part 63, pursuant to § 63.648(a) of subpart CC. The applicable requirements of subpart H for the proposed refinery are discussed in Section IV.C.6 herein.

For each wastewater stream that is both a *process wastewater stream* as defined at § 61.341 of subpart FF of 40 CFR part 61 and a *Group 1 wastewater stream* as defined at § 63.641 of subpart CC, the proposed refinery is required to comply with the provisions of subpart FF, pursuant to § 63.647(a) of subpart CC. The applicable requirements of subpart FF for the proposed refinery are discussed in Section IV.C.2 herein.

Gasoline loading racks at the proposed refinery will be subject to the loading rack provisions of subpart CC. The control requirements for these include provisions for vapor collection and processing systems and for vapor tightness of truck and railcar cargo tanks. The applicable provisions for vapor collection and processing systems are those set forth at § 63.422(b) of subpart R of 40 CFR part 63, pursuant to § 63.650(a) of subpart CC. The emission standard under subpart R and subpart CC is a VOC emission limit of 10 milligrams per liter of gasoline loaded. Under the PSD BACT requirements, the Permittee has committed to achieve a substantially more stringent emission standard using a vapor recovery system and a thermal oxidizer in series. The BACT emission limit in the proposed permit is 1.25 pounds per million gallons of gasoline loaded, which is equal to 0.15 milligrams per liter of gasoline loaded. (See Section V.G herein for a discussion of the BACT analysis for the gasoline loading racks.) The applicable provisions for vapor tightness of truck and railcar cargo tanks are those set forth at § 60.502(e) of subpart XX of 40 CFR part 60, pursuant to § 63.646(a) of subpart CC and § 63.422(c) of subpart R of 40 CFR part 63. In addition to these emission standards, the gasoline loading racks are subject to periodic inspection, testing, monitoring, recordkeeping, and reporting provisions under subpart XX of 40 CFR part 60 and under subpart R of 40 CFR part 63. These provisions are included in Section XXI of the proposed permit.

The vents from the Rich Amine Three Phase Separator, associated with the Amine Regeneration Unit, and the Sour Water Flash Drum, associated with the Sour Water Stripper, are miscellaneous process vents subject to the provisions of subpart CC. Each of these vents will be routed to the Sulfur Recovery Plant Thermal Oxidizer for control of VOC emissions in accordance with the provisions of subpart CC. These provisions are included in Sections XII, XIII, and XIV of the proposed permit. All

remaining process vents at the refinery are specifically excluded from the definition of *miscellaneous process vent* at § 63.641 of subpart CC. These include equipment leaks; relief valve discharges; vents from storage tanks; episodic releases associated with startup, shutdown, or malfunction; gaseous streams routed to the RFG system; *in situ* sampling systems; one catalytic reforming unit catalyst regeneration vent; one hydrogen plant process vent; coke drum depressuring vents; sulfur recovery plant vents; wastewater collection system vents; hydrogen plant reformer/stripper vents; and the Butane Conversion Unit catalyst regenerator vent. The Butane Conversion Unit catalyst regenerator vent is excluded because its vent stream will contain less than 20 parts per million volume (ppmv) organic HAP.

Based on information provided by the Permittee, the proposed refinery will not include any marine tank vessel loading operations.

Subpart CC is adopted by reference at A.A.C. R18-2-1101.B.21.

9. 40 CFR 63 Subpart UUU, Petroleum Refinery Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

Subpart UUU imposes HAP emission standards for the Sulfur Recovery Plant and the Catalytic Reforming Unit Catalyst Regenerator Vent. Subpart UUU also includes requirements for fluidized catalytic cracking unit catalyst regeneration vents, but the proposed refinery will not include a fluidized catalytic cracking unit.

Each of the two sulfur recovery units at the proposed refinery is subject to the control requirements under § 63.1568(a)(1) of subpart UUU. These control requirements, as well as the applicable testing, monitoring, recordkeeping, and reporting provisions for sulfur recovery units, are essentially identical to the requirements in subpart J of 40 CFR part 60. The applicable emission standard under these regulations is an exhaust SO₂ concentration of 250 ppmv and is included in the proposed permit. In addition, under the PSD BACT requirements (see Section V herein), the Permittee has committed to achieve a substantially more stringent SO₂ emission limit of 33.6 pounds per hour (lb/hr), which equates to an exhaust SO₂ concentration of approximately 50 ppmv at maximum operating rate. The provisions of subpart UUU that are applicable to the sulfur recovery units are included in Section XIV of the proposed permit.

The catalytic reforming unit catalyst regeneration vent at the proposed refinery is subject to the control requirements under subpart UUU. These requirements include an emission limit for total organic compounds, as a surrogate for organic HAP, under § 63.1566(a) and an emission limit for hydrogen chloride, as a surrogate for inorganic HAP, under § 63.1567(a).

The applicable provisions of subpart UUU also include testing, monitoring, recordkeeping, and reporting provisions. The provisions of subpart UUU that are applicable to the catalytic reforming unit are included in Section V of the proposed permit.

Two units at the proposed refinery that are not subject to the provisions of subpart UUU warrant discussion. The Hydrocracker Unit serves a similar function to a typical fluidized catalytic cracking unit, but uses a fixed reactor bed rather than a fluidized bed. The regeneration of the hydrocracking catalyst occurs off-site and infrequently, in contrast to the continuous, internal catalyst regeneration process characteristic of fluidized catalytic cracking units. The Butane Conversion Unit includes a continuous, internal catalyst regeneration process, but the vent from this process is not regulated by subpart UUU because the process unit is neither a catalytic cracking unit nor a catalytic reforming unit, as those terms are defined at § 63.1579 of subpart UUU.

Subpart UUU has not been adopted by reference into the Arizona Administrative Code, and authority to administer and enforce this regulation has not been delegated to the Director by the U.S. EPA. The Department intends to request this delegation in the near future, at which time the regulation will be incorporated by reference in Article 11 of A.A.C. R18-2.

10. 40 CFR 63 Subpart EEEE, Organic Liquids Distribution (Non-Gasoline)

The proposed refinery will include facilities for loading of liquid products into rail cars and tank trucks. All facilities for loading of gasoline products and distillate products are exempt from the provisions of subpart EEEE because the term “organic liquid” is defined at 40 CFR § 63.2406 to exclude gasoline, aviation gasoline, No. 1 distillate oil, No. 2 distillate oil, asphalt, and heavier distillate oils and fuel oils. Facilities for loading of LPG are exempt because the term “organic liquid” is defined to exclude liquids that contain less than 5 percent organic HAP by weight.

11. 40 CFR 63 Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines

The proposed refinery will include three stationary, reciprocating internal combustion engines used to drive an emergency electrical generator and two fire water pumps. Each of these engines meets the criteria to be classified as an emergency stationary reciprocating internal combustion engine under subpart ZZZZ. As such, each engine is exempt from all substantive requirements of the regulation.

12. 40 CFR 63 Subpart DDDDD, Industrial Boilers and Process Heaters

The proposed refinery will include two steam boilers fired with natural gas and eighteen process heaters fired with natural gas or RFG. These emission units will comply with the applicable provisions of subpart DDDDD, including a work practice standard for minimizing organic HAP emissions. This work practice standard is expressed as an exhaust gas CO concentration of 400 ppmvd corrected to 3 percent oxygen. The averaging period for this work practice standard is a 30-day rolling average for units with heat input capacity of 100 MMBtu/hr or greater and a 3-test-run average (effectively equivalent to a minimum 3-hour average) for units less than 100 MMBtu/hr). The work practice standard does not apply during periods of startup, shutdown, or malfunction and also does not apply when the unit is operating at less than 50 percent of its rated heat input capacity. These work practice requirements, as well as the applicable monitoring, recordkeeping, and reporting provisions, are included in the proposed permit, in each section that covers a process heater or steam boiler.

D. Arizona Administrative Code

1. A.A.C. R18-2-602, Open Burning

A.A.C. R18-2-602 prohibits open outdoor fires except under certain, specified conditions. The provisions of this regulation are included in Section XXIX of the proposed permit.

2. A.A.C. R18-2-604, Open Areas, Dry Washes, or Riverbeds

A.A.C. R18-2-604 restricts fugitive dust emissions from open areas including, but not limited to, driveways, parking areas, vacant lots, dry washes, and riverbeds. The provisions of this regulation are included in Section XXIX of the proposed permit.

3. A.A.C. R18-2-605, Roadways and Streets

A.A.C. R18-2-605 restricts fugitive dust emissions from roadways and alleys, including the transportation of materials over those roadways or alleys. The provisions of this regulation are included in Section XXIX of the proposed permit.

4. A.A.C. R18-2-606, Material Handling

A.A.C. R18-2-606 restricts fugitive dust emissions from nonpoint sources associated with operations such as material crushing, screening, handling, transporting, or conveying. The provisions of this regulation are included

in Section XXIX of the proposed permit. The provisions of this regulation are not applicable to any of the petroleum coke handling operations identified in Section XI of the proposed permit because each of these operations has an identifiable emission point.

5. A.A.C. R18-2-607, Storage Piles

A.A.C. R18-2-607 restricts fugitive dust emissions from material stacking, piling, or similar storage methods. The provisions of this regulation are included in Sections XI and XXIX of the proposed permit.

6. A.A.C. R18-2-612, Opacity of Emissions from Nonpoint Sources

A.A.C. R18-2-612 restricts opacity of visible emissions from nonpoint sources. The provisions of this regulation are included in Sections XI and XXIX of the proposed permit.

7. A.A.C. R18-2-702, General Provisions for Existing Point Sources

A.A.C. R18-2-702 restricts opacity of visible emissions from point sources. The provisions of this regulation are included in Sections V, VIII, XI, XXIII, XXVII, and XXIX of the proposed permit.

8. A.A.C. R18-2-703, Steam Generators and Fuel-Burning Equipment

A.A.C. R18-2-703 includes particulate matter and SO₂ emission standards for steam generating units and other fuel-burning equipment. This regulation is not applicable to any emission unit at the proposed refinery. The fuel-burning emission units at the proposed refinery, regardless of heat input capacity, are not regulated by A.A.C. R18-2-703 because they are covered by applicable new source performance standards at Title 18, Chapter 2, Article 9 of the State of Arizona regulations. (Specifically, subpart Db of 40 CFR part 60 is applicable to the Steam Boilers; subpart J is applicable to the Sulfur Recovery Plant Thermal Oxidizer and to all process heaters; subpart Kb is applicable to the Tank Farm Thermal Oxidizer; subpart XX is applicable to the Loading Rack Thermal Oxidizers; and subpart QQQ is applicable to the Wastewater Treatment Plant Thermal Oxidizer.) Thus, the fuel-burning emission units are not “existing sources” as that term is defined at A.A.C. R18-2-101.41.

9. A.A.C. R18-2-704, Incinerators

A.A.C. R18-2-704 limits visible emissions and particulate matter emissions from incinerators. This regulation is not applicable to any emission unit at the proposed refinery. The thermal oxidizers that will be used to control emissions of VOC, organic HAP, and reduced sulfur

compounds from the Sulfur Recovery Plant, Group “B” Storage Tanks, Truck and Rail Car Loading Racks, and Wastewater Treatment Plant are not regulated by A.A.C. R18-2-704 because they are covered by applicable new source performance standards at Title 18, Chapter 2, Article 9 of the State of Arizona regulations. (Specifically, subpart J of 40 CFR part 60 is applicable to the Sulfur Recovery Plant Thermal Oxidizer; subpart Kb is applicable to the Tank Farm Thermal Oxidizer; subpart XX is applicable to the Loading Rack Thermal Oxidizers; and subpart QQQ is applicable to the Wastewater Treatment Plant Thermal Oxidizer.) Thus, the thermal oxidizers are not “existing sources” as that term is defined at A.A.C. R18-2-101.41.

10. A.A.C. R18-2-709, Petroleum Refineries

A.A.C. R18-2-709 includes emission standards for fuel gas combustion devices at petroleum refineries. This regulation is not applicable to any combustion device at the proposed refinery because each such device is covered by an applicable new source performance standard at Title 18, Chapter 2, Article 9 of the State of Arizona regulations. (Specifically, subpart J of 40 CFR part 60 is applicable to each fuel gas combustion device.) Thus, the fuel gas combustion devices are not “existing sources” as that term is defined at A.A.C. R18-2-101.41.

11. A.A.C. R18-2-710, Petroleum Liquid Storage Vessels

A.A.C. R18-2-710 includes emission standards for petroleum liquid storage tanks. This regulation is not applicable to any storage tank at the proposed refinery because each storage tank is covered by an applicable new source performance standard at Title 18, Chapter 2, Article 9 of the State of Arizona regulations. (Specifically, subpart Kb of 40 CFR part 60 is applicable to each storage tank.) Thus, the storage tanks are not “existing sources” as that term is defined at A.A.C. R18-2-101.41.

12. A.A.C. R18-2-719, Stationary Rotating Machinery

A.A.C. R18-2-719 limits visible emissions and emissions of PM and SO₂ from internal combustion engines. The visible emissions limitation is included in Section XXVIII of the proposed permit. The PM and SO₂ emission limits are less stringent than the applicable BACT emission limits under all operating conditions and, for this reason, have been streamlined out of the proposed permit.

13. A.A.C. R18-2-724, Fossil-fuel Fired Equipment

A.A.C. R18-2-724 includes particulate matter and SO₂ emission standards for steam generating units and other fuel-burning equipment. This

regulation is not applicable to any emission unit at the proposed refinery. The fuel-burning emission units at the proposed refinery are not regulated by A.A.C. R18-2-724, regardless of heat input capacity, because they are covered by applicable new source performance standards at Title 18, Chapter 2, Article 9 of the State of Arizona regulations. (Specifically, subpart Db of 40 CFR part 60 is applicable to the Steam Boilers; subpart J is applicable to the Sulfur Recovery Plant Thermal Oxidizer and to all process heaters; subpart Kb is applicable to the Tank Farm Thermal Oxidizer; subpart XX is applicable to the Loading Rack Thermal Oxidizers; and subpart QQQ is applicable to the Wastewater Treatment Plant Thermal Oxidizer.) Thus, the fuel-burning emission units are not “existing sources” as that term is defined at A.A.C. R18-2-101.41.

14. A.A.C. R18-2-726, Sandblasting Operations

A.A.C. R18-2-726 restricts fugitive dust emissions from abrasive blasting operations. The provisions of this regulation are included in Section XXIX of the proposed permit.

15. A.A.C. R18-2-727, Spray Painting Operations

A.A.C. R18-2-727 restricts VOC emissions from spray painting operations. The provisions of this regulation are included in Section XXIX of the proposed permit.

16. A.A.C. R18-2-730, Unclassified Sources

A.A.C. R18-2-730 restricts emissions of particulate matter, SO₂, and NO_x from sources not otherwise regulated under Articles 7, 9, or 11; restricts emissions of hydrogen sulfide; and prohibits the causation of air pollution. The provisions of this regulation are included in Sections XI, XXIII, XXVII, and XXIX of the proposed permit.

17. A.A.C. R18-2-801, General Provisions for Mobile Sources

A.A.C. R18-2-801 restricts opacity of visible emissions from mobile sources not otherwise regulated under Article 8. The provisions of this regulation are included in Section XXIX of the proposed permit.

18. A.A.C. R18-2-802, Off-Road Machinery

A.A.C. R18-2-802 restricts opacity of visible emissions from trucks, graders, scrapers, rollers, locomotives, and other machinery not normally driven on completed public roadways. The provisions of this regulation are included in Section XXIX of the proposed permit.

19. A.A.C. R18-2-804, Roadway and Site-Cleaning Machinery

A.A.C. R18-2-804 restricts opacity of visible emissions from roadway and site cleaning machinery, including the exhaust from such machinery. The provisions of this regulation are included in Section XXIX of the proposed permit.

20. Article 9, New Source Performance Standards

A.A.C. R18-2-901 incorporates by reference those federal NSPS regulations for which the Department has been delegated enforcement authority by the U.S. EPA. Applicable and non-applicable NSPS regulations are discussed in Section IV.B herein.

21. Article 11, Federal Hazardous Air Pollutants

A.A.C. R18-2-1101 incorporates by reference those federal NESHAP regulations for which the Department has been delegated enforcement authority by the U.S. EPA. Applicable and non-applicable NESHAP regulations are discussed in Section IV.C herein.

E. Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) rule is codified at 40 CFR part 64, and the CAM monitoring requirements are mandatory elements of the Class I permit pursuant to A.A.C. R18-2-306(A)(3)(a)(i). Generally, the rule applies wherever the following three criteria are met:

- The emission unit is subject to an emission limitation or standard for a particular pollutant;
- The emission unit uses a control device to achieve compliance with the emission limitation or standard; and
- The emission unit has potential, pre-control device emissions greater than the applicable major source threshold.

The proposed refinery will include eight pollutant-specific emission units meeting these criteria:

- NO_x emissions controlled by the Hydrogen Reformer Heater selective catalytic reduction unit;
- H₂S emissions from the Sulfur Recovery Unit;
- VOC emissions from the Tank Farm Thermal Oxidizer;

- VOC emissions from the Rail Car Loading Rack Thermal Oxidizer;
- VOC emissions from the Truck Loading Rack Thermal Oxidizer;
- VOC emissions from the Wastewater Treatment Plant Thermal Oxidizer;
- PM emissions from the Wastewater Treatment Plant Spray Dryer; and
- PM emissions from the Cooling Tower.

However, pursuant to § 64.2(b)(1)(vi), the provisions of the CAM rule do not apply where the applicable emission limitation or standard is one “for which a part 70 or 71 permit specifies a continuous compliance determination method.” This term is defined at § 64.1 as follows:

“... a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit.”

Four of the eight pollutant-specific emission units listed above qualify for this exemption. A NO_x continuous emission monitoring system (CEMS) is required to be installed and operated on the Hydrogen Reformer Heater, and an H₂S CEMS is required to be installed and operated on Sulfur Recovery Unit exhaust. The VOC emission standards for the Tank Farm Thermal Oxidizer and Wastewater Treatment Plant Thermal Oxidizer are design/operational standards, expressed as a minimum temperature, and a continuous temperature monitoring device is required for each.

For the remaining four pollutant-specific emission units, the provisions of the CAM rule apply. The rule allows for two general approaches: continuous monitoring to determine compliance directly, such as using CEMS, or monitoring of control device operation within specified ranges of performance to provide reasonable assurance of compliance. The latter approach will be used for each of the four affected pollutant-specific emission units at the proposed refinery. The applicable CAM rule provisions are incorporated into Sections XXI, XXIII, and XXVII of the proposed permit.

V. CONTROL TECHNOLOGY ANALYSES

A. General

1. Best Available Control Technology

As noted in Section IV.A.3 herein, PSD regulations under Title I of the Federal Clean Air Act and A.A.C. R18-2-406.A are applicable to the proposed refinery. One of the substantive requirements under the PSD regulations is that, for a new major stationary source, the Best Available Control Technology, or “BACT,” must be applied to each emission unit. This requirement applies on a pollutant-specific basis. The proposed refinery is subject to the PSD provisions for nine pollutants: PM, PM₁₀, SO₂, NO_x, CO, VOC, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.

The term “best available control technology” is defined at A.A.C. R18-2-101.19 as follows:

“[A]n emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification.”

The procedures for establishing BACT are set forth at A.A.C. R18-2-406.A.4 as follows:

“BACT shall be determined on a case-by-case basis and may constitute application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques, for control of such pollutant. In no event shall such application of BACT result in emissions of any pollutant, which would exceed the emissions allowed by any applicable new source performance standard or national emission standard for hazardous air pollutants under Articles 9 and 11 of this Chapter. If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice, or operation and shall provide

for compliance by means which achieve equivalent results.”

The U.S. EPA’s interpretive policies relating to BACT analyses are set forth in several informal guidance documents. Most notable among these are the following:

- “Guidelines for Determining Best Available Control Technology (BACT),” December 1978.
- “Prevention of Significant Deterioration Workshop Manual,” October 1980.
- “New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting.” Draft. October 1990.

The Department generally uses what is termed a “top-down” procedure when making BACT determinations. This procedure is designed to ensure that each determination is made consistent with the two core criteria for BACT: consideration of the most stringent control technologies available, and a reasoned justification, considering energy, environmental and economic impacts and other costs, of any decision to require less than the maximum degree of reduction in emissions.

The framework for the top-down BACT analysis procedure used by the Department comprises five key steps, as discussed in detail below. The five-step procedure mirrors the analytical framework set forth in the draft 1990 guidance document. However, it should be noted that the Department does not necessarily adhere to the prescriptive process described in the draft 1990 guidance document. Strict adherence to the detailed top-down BACT analysis process described in that draft document would unnecessarily restrict the Department’s judgment and discretion in weighing various factors before making case-by-case BACT determinations. Rather, as outlined in the 1978 and 1980 guidance documents, the Department has broad flexibility in applying its judgment and discretion in making these determinations.

Step 1 - Identify all control options. The process is performed on a source-by-source and pollutant-by-pollutant basis and begins with the identification of available control technologies and techniques. For BACT purposes, “available” control options are those technologies and techniques, or combinations of technologies and techniques, with a practical potential for application to the subject emission units and pollutants. These may include fuel cleaning or treatment, inherently lower-polluting processes, and end-of-pipe control devices. All identified control options are listed in this step. Those that are identified as being technically infeasible or as having unreasonable energy, economic or environmental impacts or other unacceptable costs are eliminated in

subsequent steps.

Step 2 - Eliminate technically infeasible control options. In this step, the technical feasibility of identified control options is evaluated with respect to source-specific factors. Technically feasible control options are those that have been demonstrated to function efficiently on identical or similar processes. In general, if a control option has been demonstrated to function efficiently on the same type of emission unit, or another unit with similar exhaust streams, the control option is presumed to be technically feasible. For presumably technically feasible control options, demonstrations of technical infeasibility must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the control option from being employed successfully on the subject emission unit. Technical feasibility need not be addressed for control options that are less effective than the control option proposed as BACT by the permit applicant.

Step 3 - Characterize control effectiveness of technically feasible control options. For each control option that is not eliminated in Step 2, the overall control effectiveness for the pollutant under review is characterized. The control option with the highest overall effectiveness is the “top” control option. If the top control option is proposed by the permit applicant as BACT, no evaluation is required under Step 4, and the procedure moves to Step 5. Otherwise, the top control option and other identified control options that are more effective than that proposed by the permit applicant must be evaluated in Step 4. A control option that can be designed and operated at two or more levels of control effectiveness may be presented and evaluated as two or more distinct control options (i.e., an option for each control effectiveness level).

Step 4 - Evaluate more effective control options. If any identified and technically feasible control options are more effective than that proposed by the permit applicant as BACT, rejection of those more effective control options must be justified based on the evaluation conducted in this step. For each control option that is more effective than the option ultimately selected as BACT, the rationale for rejection must be documented for the public record. Energy, environmental, and economic impacts and other costs of the more effective control options, including both beneficial and adverse (i.e., positive and negative) impacts, are listed and considered.

Step 5 - Establish BACT. Finally, the most effective control technology not rejected in Step 4 is proposed as BACT. To complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit. This emission limit must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, in the case of a numerical emission limitation, the permit

must specify a reasonable compliance averaging time, consistent with established reference methods. The permit must also include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA. This database is the most comprehensive and up-to-date listing of control technology determinations available.
- Information provided by pollution control equipment vendors.
- Information provided by industry representatives and by other State permitting authorities. This information is particularly valuable in clarifying or updating control technology information that has not yet been entered into the RACT/BACT/LAER Clearinghouse.

The BACT evaluations and proposed BACT determinations for each category of emission unit at the proposed refinery are discussed in the following subsections.

2. Maximum Achievable Control Technology

As noted in Section IV.C.4 herein, case-by-case MACT regulations under 40 CFR part 63, subpart B required by A.A.C. R18-2-302.D and incorporated by reference at A.A.C. R18-2-1101.B.2 are not applicable to any emission sources at the proposed refinery.

B. Boilers and Process Heaters

As noted in Sections II.A through II.Y herein, the proposed refinery will include two steam boilers fired with natural gas and eighteen process heaters fired with natural gas or RFG.

1. BACT for Particulate Matter

For this analysis, PM₁₀ is defined to include both fine filterable particulate matter and condensible particulate matter as measured by EPA Reference Methods 201A and 202, respectively. Method 201A measures all particulate matter having an aerodynamic diameter equal to or less than nominally 10 micrometers (10⁻⁶ meters) that is collected on a glass fiber filter at the stack temperature. Method 201A will generally yield a slightly smaller result than Method 5 because particles having an

aerodynamic diameter nominally 10 micrometers or greater are excluded. Method 202 measures all particulate matter that condenses at a temperature of approximately 20 degrees Celsius (°C) after passing through a fabric filter such as that used in Method 201A. The total PM₁₀, which is the combined result of performing Method 201A and Method 202 simultaneously, may be substantially different than the PM as measured by Method 5.

Steps 1-4

The only control strategy identified for the natural gas-fired steam boilers and RFG-fired process heaters is a work practice requirement: adherence to good combustion practices. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5 - Establish BACT

The Permittee proposed 0.0075 pound per million British Thermal Units (lb/MMBtu) heat input as the BACT emission limit for PM₁₀.

Based on its review of emission levels achieved by other gas-fired combustion sources, the Department concurs that a PM₁₀ emission limit of 0.0075 lb/MMBtu heat input, higher heating value (HHV), is representative of good combustion practices with gas-fired boilers and process heaters.

The Department is aware that a small number of gas-fired combustion sources are subject to numerically lower PM₁₀ emission limits. However, the Department has determined that these lower limits are not enforceable as a practical matter and is unaware of any data demonstrating that a more stringent limit is representative of BACT.

The Department elected not to establish a separate BACT emission limit for the filterable fraction of PM or PM₁₀ emissions. Instead, the Department elected to establish a single BACT emission limit for total PM₁₀, including both filterable and condensible fractions. The emission limit established for each gas-fired boiler and process heater is 0.0075 lb/MMBtu heat input (HHV), based on a three-hour average. Compliance with this emission limit is to be demonstrated through annual performance testing using U.S. EPA Reference Methods 201 or 201A and Method 202.

2. BACT for Sulfur Dioxide

Steps 1-4

The only control option identified for the natural gas-fired steam boilers is the use of pipeline-quality natural gas. The only control option identified for the RFG-fired process heaters is the use of amine contactors to remove sulfur from RFG to the maximum extent possible. These control options are technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5 - Establish BACT

The Permittee proposed a fuel gas sulfur content of 35 ppmv as the BACT emission limit for SO₂ from RFG-fired process heaters.

Based on its review of emission levels achieved by other RFG-fired combustion sources, the Department determined that an RFG sulfur content limit of 35 ppmv is representative of the achievable level with amine contactors. The Department is not aware of any RFG-fired combustion sources that are subject to more stringent SO₂ emission limits.

The emission limit established for each RFG-fired process heater is an RFG sulfur content limit of 35 ppmv, based on a daily average. Compliance with this emission limit is to be demonstrated either through continuous SO₂ emission monitoring, continuous monitoring of total RFG sulfur content, or continuous monitoring of RFG hydrogen sulfide content along with daily sampling and analysis to determine the RFG sulfur content based on the ratio of hydrogen sulfide to total sulfur.

In addition to the RFG sulfur content limit, the BACT analysis for SO₂ emissions from the process heaters also includes equipment design and work practice requirements in order to minimize, to the greatest extent possible, emissions that would occur due to upsets. Specifically, during periods of upset at the Amine Regeneration Unit, the amine contactors used to remove hydrogen sulfide from RFG streams will continue to generate rich amine solution and to deplete the refinery's supply of lean amine solution. The permit requires that rich amine solution storage capacity and a supply of lean amine solution, sufficient to support 24 hours of refinery operation, be maintained continuously. This will ensure that excess SO₂ emissions from the process heaters are minimized while the refinery curtails operations in the event of an upset at the Amine Regeneration Unit.

The Department concludes that monitoring and performance testing to demonstrate compliance with an SO₂ emission rate limitation for natural gas-fired combustion sources would be economically unwarranted. The Department has included in the proposed permit a prohibition on burning fuels other than natural gas in the steam boilers. This serves as operational standard that satisfies the requirement for the application of

BACT for SO₂ emissions.

3. BACT for Nitrogen Oxides

Step 1 - Identify All Control Options

Identified control technologies and techniques for NO_x emissions include combustion modifications (low-NO_x burners and flue gas recirculation) and post-combustion control devices [selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and SCONO_x].

Combustion modifications can be applied in combination with one another and in combination with a post-combustion control device. Thus, a variety of control options with identified control technologies applied individually and in combination can be considered.

Step 2 - Eliminate Technically Infeasible Control Options

The Department concluded that flue gas recirculation and SCONO_x have not been demonstrated to be technically feasible for all or some of the combustion sources. Specifically, flue gas recirculation was determined by the Department not to be demonstrated for the RFG-fired process heaters at the proposed refinery. (However, this control technique is demonstrated and feasible and has been proposed by the Permittee as BACT for the natural gas-fired boilers.) Flue gas recirculation has not been demonstrated to function efficiently on process heaters that are subject to highly variable loads and that burn fuels with variable heat value. Thus, there are significant technical differences between the proposed refinery's process heaters and those combustion sources where flue gas recirculation has been demonstrated in practice. These significant technical differences preclude a determination that flue gas recirculation has been demonstrated to function efficiently on sources that are identical or similar to the proposed refinery's process heaters.

SCONO_x was determined by the Department not to be demonstrated either for the RFG-fired process heaters or for the natural gas-fired boilers. This technology has not been demonstrated to function efficiently on combustion sources burning fuels other than natural gas or on combustion sources as large as the boilers. Thus, there are significant technical differences between the proposed refinery's combustion sources and those few sources where SCONO_x has been demonstrated in practice. These significant technical differences preclude a determination that SCONO_x has been demonstrated to function efficiently on sources that are identical or similar to the proposed refinery's boilers and process heaters.

Step 3 - Characterize Control Effectiveness of Technically Feasible

Control Options

The second-ranked control option for each combustion source involves the use of technically feasible combustion modifications (i.e., low-NO_x burners with flue gas recirculation for the natural gas-fired boilers and low-NO_x burners for the process heaters). The NO_x emission level achievable with this control option varies somewhat for individual combustion sources, but is generally between 0.015 lb/MMBtu heat input (HHV) and 0.040 lb/MMBtu heat input (HHV), based on a three-hour average. This control option has been proposed by the Permittee for nine RFG-fired process heaters and for the two natural gas-fired boilers.

The highest-ranked control strategy for each combustion source involves the use of SCR in addition to the identified combustion modifications. Again, the NO_x emission level achievable with this control option varies somewhat for individual combustion sources, but is generally between 0.0075 lb/MMBtu heat input (HHV) and 0.012 lb/MMBtu heat input (HHV), based on a three-hour average. This control option has been proposed by the Permittee for nine RFG-fired process heaters.

The combination of SCR with state-of-the-art combustion modifications for controlling NO_x emissions is a control strategy that, in some applications, can perform at two or more levels of control effectiveness. Specifically, for some of the process heaters, by increasing the permissible ammonia slip level and increasing the catalyst replacement frequency, the effectiveness of the SCR system in maintaining a high degree of NO_x emission reduction may be increased. For these process heaters, the Department has evaluated the high-efficiency and the moderate-efficiency SCR systems as two distinct control options.

Other technically feasible control strategies were not given in-depth consideration by the Department. These control strategies are SCR or SNCR applied without combustion modifications (i.e., in conjunction with conventional burners) and SNCR applied in conjunction with combustion modifications. Based on the Department's engineering judgment, low-NO_x burners are preferable to conventional burners due to the magnitude of the emission reductions achievable at relatively little cost, and SCR is preferable to SNCR for the same reason.

Step 4 - Evaluate More Effective Control Options

In the case of each combustion source, the second-ranked control option (i.e., combustion controls) will not cause any adverse energy, environmental, or economic impacts. The highest-ranked control option (i.e., with the addition of selective catalytic reduction), when considered in comparison with the second-ranked control option, will cause adverse

energy and economic impacts and will yield both beneficial and adverse environmental impacts. The adverse energy impact is due to the electrical requirements of the SCR system operation and to the reduction in energy efficiency attributable to the pressure drop across the SCR catalyst grid. To the extent that the decreased energy efficiency results in an economic penalty, that cost is considered in the evaluation of adverse economic impacts, discussed below. With that exception, the adverse energy impacts are relatively minor and are not a significant factor in the BACT decision.

The adverse environmental impacts attributable to the addition of the SCR system include the use of ammonia reagent, with associated storage, shipping and handling risks; the handling and disposal of a spent catalyst as a solid waste stream; ammonia emissions; and, indirectly, formation of PM₁₀ and visible plume from ammonia salt precipitates. The proposed refinery will use aqueous ammonia as the active reagent in its SCR systems, as opposed to the more hazardous anhydrous ammonia, so this is a relatively minor environmental impact and is not a significant factor in the BACT decision. Similarly, extensive industry experience with SCR systems indicates that the removal and disposal of spent SCR catalyst can be conducted safely, with insignificant risk to the environment. To the extent that the safe removal and disposal of spent catalyst results in an economic penalty, that cost is considered in the evaluation of adverse economic impacts, discussed below. Otherwise, the environmental impacts of spent catalyst removal and disposal are not a significant factor in the BACT decision.

Ammonia “slip,” or ammonia that is injected in the SCR system and exits the unit without participating in the chemical reduction of NO_x emissions, leads directly to emissions of ammonia and indirectly to the formation of visible plumes, secondary particulate matter, and visibility impairment. These problems are less severe when the SCR catalyst is new and activity is highest, because the ammonia injection rate can be set to near-stoichiometric levels. As the catalyst ages, its activity decreases, and a higher ammonia reagent injection rate is required to maintain the rate of the NO_x reduction reaction necessary for continuous compliance with NO_x emission limits. This tends to result in increasing levels of ammonia slip.

The more stringent the NO_x emission limits, and the less frequent the catalyst replacement, the greater are the adverse environmental impacts from ammonia slip. With typical average NO_x concentrations less than 20 parts per million volume, dry basis (ppmvd), at the inlet to the SCR systems, as would be the case for the process heaters at the proposed refinery, the SCR systems can be designed and operated to achieve NO_x concentrations below 8 ppmvd, corrected to zero percent stack gas oxygen

concentration, based on a three-hour average, on a consistent and reliable basis.² For the purposes of this BACT analysis, this concentration equates to a NO_x emission limit of 0.0085 lb/MMBtu heat input (HHV). Achieving this very low NO_x concentration requires injection of larger amounts of ammonia reagent and, consequently, higher permissible ammonia slip levels. For the purposes of evaluating the environmental impacts of the high-efficiency SCR system in this BACT analysis, the Department has concluded that an allowable ammonia slip level of 15 ppmvd, corrected to zero percent stack gas oxygen concentration and based on a three-hour average, is representative of the level achievable with this system.

For the purposes of this BACT analysis, the NO_x emission limit achievable with the moderate-efficiency SCR system is 0.0125 lb/MMBtu heat input (HHV). This relatively small increase in the NO_x emission limit, as compared to the high-efficiency SCR system, allows for significant decreases in ammonia injection rate and ammonia slip level. For the purposes of evaluating the environmental impacts of the moderate-efficiency SCR system in this BACT analysis, the Department has concluded that an allowable ammonia slip level of 5 ppmvd, corrected to zero percent stack gas oxygen concentration and based on a three-hour average, is representative of the level achievable with this system.

Ammonia slip, as mentioned previously, leads directly to emissions of ammonia and indirectly to the formation of visible plumes, secondary particulate matter, and visibility impairment. The adverse environmental impacts associated with these effects, as they would result from application of SCR systems to the RFG-fired process heaters at the proposed refinery, are potentially severe. These adverse environmental impacts are particularly severe for the high-efficiency SCR system when considered in conjunction with its beneficial environmental impacts, and even more so when these impacts are compared with those of the moderate-efficiency SCR system. The moderate-efficiency system is characterized by a NO_x emission limit of 0.0125 lb/MMBtu heat input

² The actual and design control efficiencies of the high-efficiency SCR system discussed here are considerably higher than the 60 percent that is implied by an inlet NO_x concentration of 20 ppmv and an outlet NO_x concentration of 8 ppmv. The inlet NO_x concentration of 20 ppmv represents an uncorrected, long-term average and equates to a long-term average of approximately 0.025 lb/MMBtu heat input (HHV). This long-term average emission rate is typical of a heater with combustion controls designed to achieve a NO_x emission level of 0.040 lb/MMBtu heat input (HHV), based on a three-hour average, on a consistent and reliable basis. The apparent inconsistency in these values is attributable to the short-term variability in emission rate, which is more pronounced for RFG-fired process heaters because they are subject to variable loads and are fired with fuel of variable composition.

(HHV) and an ammonia slip level of 5 ppmvd (both on a three-hour average). The high-efficiency system is characterized by a NO_x emission limit of 0.0085 lb/MMBtu heat input (HHV) and an ammonia slip level of 15 ppmvd (both on a three-hour average). In terms of mass emission rate, the ammonia emissions from the moderate-efficiency and high-efficiency SCR systems are approximately 0.0019 lb/MMBtu heat input (HHV) and 0.0058 lb/MMBtu heat input (HHV), respectively.

A representative RFG-fired process heater with a heat input capacity of 300 MMBtu/hr will be used to illustrate the environmental impacts of the identified NO_x control options and their impacts on NO_x and ammonia emissions. The incremental environmental impacts of the moderate-efficiency SCR system as compared to the no-SCR option include a reduction in NO_x emissions of 69 percent, or 8.2 lb/hr, and an increase in ammonia emissions of 0.6 lb/hr. The incremental environmental impacts of the high-efficiency SCR system as compared to the moderate-efficiency SCR system include a reduction in NO_x emissions of 32 percent, or 1.2 lb/hr, and an increase in ammonia emissions of 1.2 lb/hr. This information is summarized in the following table:

	NO _x Emission Rate (lb/hr)	Decrease (lb/hr)	Ammonia Emission Rate (lb/hr)	Increase (lb/hr)
No SCR	12.0	n/a	0.0	n/a
Moderate- Efficiency SCR	3.8	8.2	0.6	0.6
High- Efficiency SCR	2.6	1.2	1.7	1.2

Based on this information, the Department concludes that the beneficial environmental impacts of the moderate-efficiency SCR system clearly outweigh its adverse environmental impacts. The Department cannot conclude that the beneficial environmental impacts of the high-efficiency SCR system outweigh its adverse environmental impacts. Thus, the high-efficiency SCR system was not given further consideration as a NO_x control option for RFG-fired process heaters at the proposed refinery.

For the natural gas-fired steam boilers, the high-efficiency SCR system was the only SCR system considered. This was done because the boilers are not subject to variable loads and variable fuel composition as are the RFG-process heaters. Therefore, the ammonia slip impacts would not be

expected to be significant.

The final consideration in the evaluation of alternative NO_x control options is the adverse environmental impact associated with the application of SCR for the natural gas-fired boilers and for those RFG-fired process heaters where the Permittee has proposed the use of combustion controls as BACT. The Department's evaluation of these adverse economic impacts is based, in part, on cost information provided by the Permittee in Table 6.2-4 of its revised permit application. The Department also conducted an independent evaluation of the economic impacts of SCR systems for the natural gas-fired steam boilers and for the RFG-fired process heaters using the cost information developed by the U.S. EPA for its January 2001 presumptive BACT guidance for NO_x emissions from new refinery process heaters.³ The Department's evaluation shows that the incremental cost effectiveness of adding SCR systems to those combustion sources where the Permittee has proposed the use of combustion controls as BACT ranges from \$15,000 to \$38,000 per ton of NO_x emission reduction (\$15,000 to \$28,000 per ton at the RFG-fired process heaters and \$38,000 per ton at the natural gas-fired steam boilers). The Department considers these to be significant, adverse economic impacts.⁴

Considering these adverse economic impacts as well as the adverse environmental impacts and the relatively insignificant air quality benefits that would result, the Department concludes that requiring SCR for those combustion sources where the Permittee has proposed the use of combustion controls as BACT cannot be justified. Therefore, the

³ See January 19, 2001 memorandum from J.S. Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to Air Division Directors, U.S. EPA Regions I-X. "BACT and LAER for emissions of NO_x and VOC at Tier 2/Gasoline Sulfur Refinery Projects."

⁴ The average cost effectiveness of the most effective control option ranges from approximately \$2,000 to \$10,000 per ton at the RFG-fired process heaters and \$800 per ton at the natural gas-fired steam boilers. The average cost effectiveness value for the boilers is based on an uncontrolled (baseline) emission factor of 0.28 lb/MMBtu heat input (HHV), from AP-42 Section 1.4. The average cost effectiveness values for the process heaters are based on an uncontrolled (baseline) emission factor of 0.217 lb/MMBtu heat input (HHV), from U.S. EPA guidance regarding BACT for refinery process heaters. (See, January 19, 2001 memorandum from J.S. Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to Air Division Directors, U.S. EPA Regions I-X. "BACT and LAER for emissions of NO_x and VOC at Tier 2/Gasoline Sulfur Refinery Projects.") Selection of these baseline emission rates is inherently arbitrary; thus, the Department gave little consideration to average cost effectiveness when making its preliminary BACT determinations for NO_x emissions from boilers and process heaters.

Department concurs with the Permittee's proposed selection of a control option representing BACT for NO_x emissions from each natural gas-fired steam boiler and each RFG-fired process heater.

Step 5 - Establish BACT

As discussed in Steps 2-4 above, the NO_x control option proposed by the Permittee for the natural gas-fired steam boilers is the use of low-NO_x burners and flue gas recirculation. The Permittee has proposed a NO_x emission limit of 0.0125 lb/MMBtu heat input, based on a three-hour average, representing the maximum degree of emission reduction achievable with the proposed control option. The Department agrees that this proposal generally represents BACT for NO_x emissions from the natural gas-fired boilers and has included in the draft permit a NO_x emission limit of 0.0125 lb/MMBtu heat input (HHV), based on a three-hour average. This is equivalent to a stack gas NO_x concentration of 10 ppmvd, corrected to three percent stack gas oxygen concentration, consistent with the basis for the Permittee's proposed emission limits.

The NO_x control option proposed by the Permittee for nine of the RFG-fired process heaters is the use of low-NO_x burners and SCR. The nine heaters that are proposed to be equipped with SCR are as follows:

Name	ID Number
Atmospheric Crude Charge Heater	B-01300
Vacuum Crude Charge Heater	B-02100
Catalytic Reforming Unit Charge Heater	B-05110
Catalytic Reforming Unit Interheater No. 1	B-05120
Catalytic Reforming Unit Interheater No. 2	B-05130
Hydrogen Reformer Heater	B-07010
Butane Conversion Unit Isostripper Reboiler	B-15110
Butane Conversion Unit Dehydrogenation Reactor Charge Heater	B-15310
Butane Conversion Unit Dehydrogenation Reactor Interheater	B-15320

For each of these heaters, the Permittee has proposed a NO_x emission limit of 0.0125 lb/MMBtu heat input, based on a three-hour average. As

discussed in Step 4 above, the Department considers this to be representative of the NO_x emission level achievable with a moderate-efficiency SCR system on RFG-fired process heaters. The Department agrees that the Permittee's proposal generally represents BACT for NO_x emissions from these process heaters and has included in the draft permit a NO_x emission limit of 0.0125 lb/MMBtu heat input (HHV), based on a three-hour average. This is equivalent to a stack gas NO_x concentration of 10 ppmvd, corrected to three percent stack gas oxygen concentration, consistent with the basis for the Permittee's proposed emission limits. Recognizing the likelihood that a lower limit will be achievable by the time these SCR-equipped heaters begin operation, the permit also includes a provision for conducting an SCR performance demonstration study during the first 24 months of operation. Based on the achievable NO_x levels demonstrated in this study, the NO_x BACT limits for these heaters may be adjusted by the Department through a separate permitting action.

The NO_x control option proposed by the Permittee for each of the remaining nine RFG-fired process heaters is the use of low-NO_x burners. This technology achieves reduced NO_x formation rates, relative to conventional burners, through proprietary design changes that are specific to the products offered by individual equipment. Generally, low-NO_x burners minimize formation of prompt NO_x by staging the introduction of air, providing control over the air-to-fuel ratio throughout the combustion zone, and allowing the fuel to burn under fuel-lean conditions. Formation of thermal NO_x is minimized by ensuring that the combustion region contains a high amount of combustion products and diluent air, with temperatures much lower than the adiabatic flame temperature, so that the peak flame temperature is maintained as low as possible. The NO_x emission reductions achievable with low-NO_x burner technology are generally less for RFG firing than for natural gas firing. The two primary reasons for this are the variable nature of RFG composition, which adversely affects the ability to maintain extremely fuel-lean conditions throughout the combustion zone while still maintaining flammability, and the high adiabatic flame temperature of RFG relative to natural gas.

For the nine RFG-fired process heaters that are proposed to be equipped with low-NO_x burners, the Permittee has proposed NO_x emission limits, individually, ranging from 0.025 to 0.035 lb/MMBtu heat input (HHV), based on a three-hour average. The achievable NO_x level (i.e., the proposed NO_x emission limit) for each heater is determined independently and is dictated by the configuration of the particular heater. The required turndown ratio and heat release, firebox dimensions, and burner placement for a particular heater, to the extent that they affect burner design elements such as air-to-fuel ratio and flame length, all constrain the optimization of burner design and performance. The nine heaters in this category, and the Permittee's proposed NO_x emission limit for each heater, are as follows:

Name	ID Number	NO _x Emission Limit (lb/MMBtu heat input) (HHV)
Hydrocracker Unit Charge Heater	B-10200	0.034
Hydrocracker Main Fractionator Heater	B-10500	0.025
Naphtha Hydrotreater Charge Heater	B-04200	0.030
Catalytic Reforming Unit Debutanizer Reboiler	B-05609	0.030
Distillate Hydrotreater Charge Heater	B-08200	0.033
Distillate Hydrotreater Splitter Reboiler	B-08509	0.032
Delayed Coking Unit Charge Heater No. 1	B-14110A	0.030
Delayed Coking Unit Charge Heater No. 2	B-14110B	0.030
Spray Dryer Heater	B-26903	0.030

The Department concludes that the Permittee's proposed NO_x emission limits represent BACT for these nine RFG-fired process heaters, based on a three-hour average. The Department has included in the draft permit the NO_x emission limits listed above. Compliance with each NO_x emission limit is to be demonstrated through the use of NO_x continuous emission monitoring systems.

With the emission limits proposed as BACT by the Department, the total allowable NO_x emissions from the natural gas-fired steam boilers and the RFG-fired process heaters at the proposed refinery will be approximately 312 tons per year.

4. BACT for Carbon Monoxide

Steps 1-4

The only control strategy identified for the RFG-fired process heaters and

the natural gas-fired steam boilers is adherence to good combustion practices. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5 - Establish BACT

The Permittee has proposed BACT emission limits for the RFG-fired process heaters and the natural gas-fired steam boilers of 0.040 lb/MMBtu and 0.016 lb/MMBtu, respectively, each based on a rolling three-hour average. The Department agrees that this proposal represents BACT for CO.

The Department is aware that RFG-fired process heaters adhering to good combustion practices can achieve lower CO emission levels if state-of-the-art combustion controls are not used to minimize NO_x emissions. However, because formation rates of CO and NO_x in a heater or furnace are inversely related, the Department must weigh the relative effect of increased CO and NO_x emissions when making its determination of BACT for CO emissions from the RFG-fired process heaters. Based on this consideration, the Department has concluded that the applicant's proposal represents BACT. The Department is not aware of any similar emission units that achieve more stringent CO emission limits while achieving comparable NO_x emission limits.

Compliance with each CO emission limit is to be demonstrated through the use of a CO continuous emission monitoring system.

5. BACT for Volatile Organic Compounds

Steps 1-4

The only control strategy identified for the RFG-fired process heaters and the natural gas-fired steam boilers is adherence to good combustion practices. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5 - Establish BACT

The Department concludes that monitoring and performance testing to demonstrate compliance with a VOC emission rate limitation for gas-fired combustion sources would be economically unwarranted. The Department further concludes that the emission limitations representing BACT for CO emissions (0.04 lb/MMBtu for the RFG-fired process heaters and 0.016 lb/MMBtu from the natural gas-fired steam boilers, each based on a rolling three-hour average) serve as operational standards that satisfy the requirement for the application of BACT for VOC emissions.

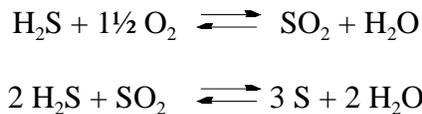
Therefore, no separate VOC emission standard for combustion sources has been imposed in the proposed permit.

C. Sulfur Recovery Units

In addition to the two Sulfur Recovery Units, the Sulfur Recovery Plant includes two Sulfur Pits, a Sulfur Rail Car Loading Rack, and a Sulfur Truck Loading Rack. These emission units are addressed separately.

As discussed in detail in Section II.N.1 herein, the purpose of the Sulfur Recovery Plant is to provide for safe disposal of the acid gas product streams from the Sour Water Stripper and the Amine Regeneration Unit. The configuration proposed by the applicant comprises two parallel Claus sulfur recovery units (SRU's), a tail gas treatment unit (TGTU), and a tail gas thermal oxidizer. This is the configuration used by most petroleum refineries. The capacity of the proposed Sulfur Recovery Plant is 608 long tons per day of liquid elemental sulfur product.

Each proposed Claus SRU will employ a three-stage reactor train to convert feed sulfur, in the form of hydrogen sulfide, into elemental sulfur. The first reactor stage is thermal and non-catalytic; the second and third reactor stages are catalytic. The primary chemical reactions are as follows:



The system is operated substoichiometrically with air, such that only one third of the H_2S is oxidized to SO_2 . This oxidation reaction occurs primarily in the first reactor. The second reaction begins in the first reactor and continues in the two catalytic reactors. Each of the three reactor stages is followed by a condenser that cools, condenses, and removes the elemental sulfur. At normal operating temperatures and pressures, and assuming acid gas H_2S concentration of approximately 75 percent, the Claus process is thermodynamically limited to a sulfur recovery efficiency of approximately 97 to 98 percent. The achievable efficiency decreases with lower acid gas H_2S concentration.

In addition to the two primary chemical reactions described above, secondary reactions also occur due to impurities in the system. Most importantly, hydrocarbons in the acid gas streams entering the thermal reactor are partially oxidized to form carbon dioxide and water, and carbon dioxide and unreacted hydrocarbons react with sulfur to form carbonyl sulfide (COS) and carbon disulfide (CS_2). These carbon-sulfur compounds may be partially hydrolyzed in the first catalytic reactor to form H_2S , but largely flow unreacted through the SRU.

The tail gas exiting the third condenser of the Claus SRU flows to the TGTU.

The tail gas is first combined with natural gas before entering the catalytic hydrogenation reactor, where residual SO₂ is hydrogenated to form H₂S according to the following equation:



In addition, a portion of the residual COS and CS₂ from the Claus SRU is hydrolyzed to form H₂S according to the following equations:



Finally, the gas exiting the TGTU hydrogenation reactor is routed to a series of amine absorber columns where an aqueous solution of methyl diethanolamine (MDEA) is used to scrub H₂S from the TGTU tail gas. The H₂S is stripped from the rich MDEA solution and routed back to the front end of the Claus SRU. The overhead stream from the final amine absorber column is routed to a thermal oxidizer for destruction of residual H₂S, COS, and CS₂.

The overall sulfur recovery efficiency achievable with the equipment Sulfur Recovery Plant configuration proposed by the applicant is approximately 99.97 percent.

1. BACT for Sulfur Dioxide

Step 1 - Identify All Control Options

Although sulfur may be sold as a byproduct, the entire Sulfur Recovery Plant exists primarily for the purpose of reducing air pollution. Therefore, for the purposes of this BACT analysis, all of the identified control technologies are considered air pollution control devices; none of the identified control technologies are considered alternative production processes.

The simplest SO₂ control strategy would involve simply eliminating the sulfur recovery plant, and allowing the acid gases from the amine regeneration unit and the sour water stripper to be emitted to the atmosphere.

An alternative control strategy allowing elimination of the SRU's and the TGTU would involve using a combustion device to burn the acid gases, thereby generating SO₂, in conjunction with a wet scrubber.

Four other control options are the equipment configuration proposed by the applicant and three slight variations on that configuration: The Claus

SRU's could be installed and operated without the TGTU or the thermal oxidizer; with the TGTU, but without the thermal oxidizer; or with the thermal oxidizer and without the TGTU.

In any of the configurations described above (i.e., SRU technology with or without TGTU and thermal oxidizer), the proposed two Claus units could be replaced with a different number of Claus units, such as one large unit or three smaller units. Also, regardless of the number of Claus units used, any of the three-stage Claus units could be replaced with two-stage Claus units. Finally, the one large TGTU could be replaced with two or more TGTU's.

Other alternatives include a number of proprietary adaptations of the Claus SRU technology. These proprietary adaptations generally operate by extending the Claus reaction to improve the thermodynamically achievable sulfur conversion efficiency. The first of the proprietary adaptations identified by the Department is the Superclaus[®] process. The Superclaus[®] process is a conventional Claus process, with a proprietary catalyst replacing the conventional, activated alumina Claus catalyst in the final catalytic reactor stage. The proprietary catalyst in the Superclaus[®] process selectively oxidizes H₂S to form elemental sulfur and water according to the following equation:



The Superclaus[®] process reportedly increases the thermodynamically achievable sulfur recovery efficiency to approximately 99 percent, as compared to an achievable efficiency less than 98 percent with the conventional Claus process.

The Euroclaus[®] process is an enhancement of the Superclaus[®] process, with a hydrogenation reactor inserted upstream of the final catalytic reactor stage. This hydrogenation reactor reduces the SO₂ concentration in the final reactor stage, which reportedly increases the thermodynamically achievable sulfur recovery efficiency to approximately 99.5 percent.

The Mobil Oil Direct Oxidation Process, like the Euroclaus[®] process, involves a hydrogenation reactor and a catalytic direct oxidation reactor added to the back end of a Claus SRU. This process reportedly increases the thermodynamically achievable sulfur recovery efficiency to approximately 99 percent.

Several proprietary adaptations of the Claus process use oxygen enrichment in order to improve the temperature control in the first-stage thermal reactor. These processes include the COPE[™], OxyClaus[®], and

SURE[®] processes. These processes reportedly have thermodynamically achievable sulfur recovery efficiencies of approximately 98 percent.

The Selectox process is similar to the conventional Claus process, with a catalytic oxidizer in place of the first-stage thermal reactor. This process reportedly has a thermodynamically achievable sulfur recovery efficiency of approximately 98 percent.

The Sulfreen[®] process utilizes a conventional Claus process, with an additional Claus-type reactor after the final sulfur condenser. This additional reactor operates at a temperature below the sulfur dew point and adsorbs the sulfur on the Claus catalyst. Each of the two beds in the additional reactor is cycled between adsorption and regeneration; during the regeneration cycle, the hot gases are produced in an integral heater and, after desorbing the sulfur from the catalyst, are passed through an integral condenser. Operation of the additional reactor at a sub-dew point temperature reportedly improves the thermodynamically achievable sulfur recovery efficiency to approximately 99 percent. Variations on the Sulfreen[®] process include HydroSulfreen[®], which includes a hydrogenation/hydrolysis reactor upstream of the Sulfreen[®] reactor, and DoxoSulfreen[®], which includes all components of the HydroSulfreen[®] process, plus a direct oxidation reactor downstream of the Sulfreen[®] reactor. HydroSulfreen[®] and DoxoSulfreen[®] reportedly improve the achievable sulfur recovery efficiency to approximately 99.7 percent and 99.9 percent, respectively.

The Maxisulf, CBA, Clinsulf[®], and MCRC[™] processes are similar to the Sulfreen[®] process, but without the integral heater and the recycle function in the sub-dew point part of the process. Instead, the regeneration gas is drawn from the final sulfur condenser in the Claus process. Thermodynamically achievable sulfur recovery efficiencies are similar to those for the Sulfreen[®] process.

The Wellman-Lord, CANSOLV[®], and CLINTOX processes are essentially wet scrubbers in which proprietary solvents are used for SO₂ removal. Any of these technologies would require an upstream combustion device in order to convert reduced sulfur compounds to SO₂. Any could be used with or without SRU's upstream of the combustion device. When used in conjunction with an upstream Claus SRU, these technologies allow the SO₂ to be stripped from the solvent and returned to the front end of the SRU. When installed in conjunction with an upstream Claus SRU, each of these technologies reportedly is capable of achieving a sulfur recovery efficiency in excess of 99.9 percent.

Stretford, Z-SORB, LO-CAT[®], and CrystaSulf[®] are proprietary liquid-phase oxidation-reduction technologies providing indirect oxidation of

H₂S to form elemental sulfur and water according to the equation presented above (in the description of the Superclaus[®] process). The Stretford process uses a vanadium-based chelating agent, the Z-SORB process uses a zinc-based chelating agent, and the LO-CAT[®] and CrystaSulf[®] technologies use proprietary, iron-based chelating agents. When installed in conjunction with an upstream Claus SRU and hydrogenation/hydrolysis reactor, each of these technologies reportedly is capable of achieving a sulfur recovery efficiency in excess of 99.9 percent.

The Shell Claus Offgas Treating (“SCOT”) process is the most commonly used process for removal of sulfur from Claus SRU vent streams and is the basis for the TGTU at the proposed ACF refinery. As described above, the applicant has proposed to use an MDEA-based solvent in the TGTU amine absorber columns. Variations on this control technology would involve the use of proprietary solvents, such as Sulften[®], Flexsorb[®] SE, or Flexsorb[®] SE Plus, in place of the MDEA solvent. The SCOT process can be applied in TGTU service with or without a downstream thermal oxidizer.

Step 2 - Eliminate Technically Infeasible Control Options

Several of the identified, proprietary technologies are considered technically infeasible because, based on information available to the Department, they have not been demonstrated to function efficiently in removing sulfur from acid gas streams from petroleum refinery sour water strippers and amine regeneration units. These include CANSOLV[®], CLINTOX, CrystaSulf[®], and LO-CAT[®].

Any control strategy involving the use of a combustion device to burn the acid gases to generate SO₂, regardless of the efficiency of the wet scrubber used to control these SO₂ emissions, is a technically infeasible control option because it would not meet the NSPS requirements at 40 CFR 60 subpart J.

Using a conventional Claus SRU without a TGTU or wet scrubber, either with or without a thermal oxidizer, also is a technically infeasible control option because it would not meet the NSPS requirements at 40 CFR 60 subpart J. The same is true of this configuration if the Claus SRU is replaced with any of the Claus adaptations that use oxygen enrichment (i.e., COPE[™], OxyClaus[®], and SURE[®]) or the Superclaus[®], Mobil Oil Direct Oxidation, Selectox, Sulfreen[®], Maxisulf, CBA, Clinsulf[®], or MCRC[™] processes.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The equipment configuration proposed by the applicant is the third-ranked SO₂ control option. This control option comprises two, three-stage Claus SRU's followed by a TGTU and a thermal oxidizer. This control option will achieve an overall sulfur recovery efficiency of approximately 99.97 percent and a maximum SO₂ emission rate of 33.6 lb/hr.

The second-ranked SO₂ control option comprises any number of SRU's in parallel, followed by any number of TGTU's in parallel. Like the configuration proposed by the applicant, this control option also would achieve an overall sulfur recovery efficiency of approximately 99.97 percent. The maximum SO₂ emission rate would be considerably less than 33.6 lb/hr, because most of the unrecovered sulfur would be emitted as reduced sulfur compounds.

The top-ranked SO₂ control option is a configuration with no SRU and no combustion device, simply allowing all acid gases to be emitted to the atmosphere. The sulfur recovery efficiency of this control option is zero, and essentially zero SO₂ emissions would occur.

The Department has identified several alternative control strategies that are similar to that proposed by the applicant and that may be able to achieve similar control efficiencies. These include the following:

- One, three-stage Claus SRU followed by any number of parallel TGTU's and a downstream thermal oxidizer.
- Three, three-stage Claus SRU's followed by any number of parallel TGTU's and a downstream thermal oxidizer.
- Either of the two control options listed above, or the control option proposed by the applicant, with the Claus SRU or SRU's replaced by any of the following 15 alternative SRU technologies: Superclaus[®], Euroclaus[®], COPE[™], OxyClaus[®], SURE[®], Stretford, Mobil Oil Direct Oxidation, Selectox, Sulfreen[®], HydroSulfreen[®], DoxoSulfreen[®], Maxisulf, CBA, Clinsulf[®], or MCRC[™] technology. With 3 alternative configurations and 15 alternative technologies, this yields a total of 45 process modification control options.
- Any of the 45 control options identified above, with the MDEA-based SCOT TGTU replaced by a Wellman-Lord scrubber or by a SCOT-type TGTU using Sulften[®], Flexsorb[®] SE, or Flexsorb[®] SE Plus amine solution. With 45 identified process modification control options and 4 identified add-on control options, this yields a total of 180 alternative control strategies.

The Department recognizes that the 15 identified, technically feasible, alternative SRU technologies and the 4 identified, technically feasible, alternative TGTU technologies have nominal control efficiencies that are

similar to the nominal efficiencies achievable with the SRU and TGTU technologies proposed by the applicant. However, the Department is not aware of any installation where any of the above-listed 180 alternative control strategies has been demonstrated to be capable of achieving a control effectiveness higher than the 99.97 percent sulfur recovery efficiency or an emission limit more stringent than the 33.6 lb/hr proposed by the applicant. Based on its review of the available literature, the alternative SRU technologies are designed to provide either more economical operation (e.g., a proprietary Claus adaptation using oxygen enrichment or a SCOT-type TGTU using a proprietary amine solution) or to allow regulatory requirements to be met without the use of TGTU technology (e.g., Euroclaus[®]), not to allow improvement upon the overall performance achievable with the equipment configuration proposed by the applicant.

The Department also notes that equipment reliability is of paramount importance in identifying the most effective SO₂ control option for the Sulfur Recovery Plant at the proposed ACF refinery. Hypothetically, even if one of the identified, alternative technologies were capable of improving the sulfur recovery efficiency to 99.98 percent, this would result in an SO₂ emission reduction of less than 50 tons per year. (The Department emphasizes that this value is purely for illustration; there is absolutely no available information to indicate that such higher control efficiency is, in fact achievable.) When operating at its nominal maximum short-term feed rate capacity of approximately 800 long tons per day, the plant is processing nearly 75,000 pounds of sulfur per hour. At this rate, if the Sulfur Recovery Plant were to experience a total of only 40 minutes of unanticipated shutdown time per year, the emissions from acid gas flaring during the shutdown time would more than offset the improved sulfur recovery efficiency. This represents an equipment availability threshold of more than 99.992 percent, which is extremely high for any industrial equipment. For this reason, the Department agrees in principle with the applicant's proposed use of the most widely used and demonstrated sulfur recovery plant equipment configuration in the petroleum refining industry.

Step 4 - Evaluate More Effective Control Options

The top-ranked and second-ranked control options are not representative of BACT due to the adverse environmental impacts that would result. Each of these control options would allow sulfur to be emitted to the atmosphere at a rate at least as high as the control option proposed by the applicant and in a form that is more toxic than SO₂.

Step 5 - Establish BACT

The Permittee proposed an SO₂ BACT emission limit of 33.6 lbs/hr, based

on 99.97 percent sulfur recovery efficiency.

Based on its review of emission levels achieved by other state-of-the-art sulfur recovery plants, the Department determined that the Permittee's proposal represents BACT. The proposed SO₂ BACT emission limit is 33.6 lb/hr, based on a one-hour average, using two parallel, three-stage Claus sulfur recovery units with a TGTU and a thermal oxidizer. The Department is not aware of any sulfur recovery plant that is subject to more stringent emission limits for SO₂ and other sulfur compounds.

The BACT analysis for this equipment also addresses SO₂ emissions that would occur from the TGTU thermal oxidizer or the emergency flares during an upset at the Sulfur Recovery Plant. (The feed materials for the sulfur recovery plant, comprising sour gas from the Amine Regeneration Unit and offgas from the Sour Water Stripper, are rich in hydrogen sulfide. The toxicity of hydrogen sulfide is such that these gas streams must be combusted rather than released directly to the atmosphere.) In order to minimize these emissions to the greatest extent possible, the proposed permit includes design and work practice requirements for the Amine Regeneration Unit and the Sour Water Stripper. Specifically, in the event of an upset that results in flaring of acid gases or excess SO₂ emissions from the sulfur recovery plant, the Permittee is required to re-route the Amine Regeneration Unit and Sour Water Stripper feed materials (i.e., rich amine solution and sour water) within 15 minutes; to curtail operations at upstream process units where rich amine solution and sour water are generated; and to maintain storage capacity for rich amine solution and sour water sufficient to support 24 hours of refinery operation.

2. BACT for Reduced Sulfur Compounds

This BACT analysis covers three separate PSD-regulated pollutants that are practically equivalent for petroleum refinery sulfur recovery plants. These are hydrogen sulfide; reduced sulfur compounds, which comprises hydrogen sulfide, carbonyl sulfide, and carbon disulfide; and total reduced sulfur, which comprises hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide.

Step 1 - Identify All Control Options

The identified control options and control strategies for emissions of reduced sulfur compounds are the same as those identified for SO₂ emissions.

Step 2 - Eliminate Technically Infeasible Control Options

The technically feasible and infeasible control options and control strategies for emissions of reduced sulfur compounds are the same as those identified for SO₂ emissions.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The equipment configuration proposed by the applicant is the top-ranked control option for emissions of reduced sulfur compounds. This control option comprises two, three-stage Claus SRU's followed by a TGTU and a thermal oxidizer. This control option will achieve an overall sulfur recovery efficiency of approximately 99.97 percent and a maximum H₂S emission rate of 0.089 lb/hr.

As in the SO₂ BACT analysis, the Department has identified several alternative control options that are similar to that proposed by the applicant and that may be able to achieve similar control efficiencies and H₂S emission rates. However, the Department is not aware of any installation where any of the alternative control options has been demonstrated to be capable of achieving a control effectiveness higher than the 99.97 percent sulfur recovery efficiency or an emission limit more stringent than the 0.089 lb/hr proposed by the applicant.

Step 4 - Evaluate More Effective Control Options

The equipment configuration proposed by the applicant is the top-ranked control option for emissions of reduced sulfur compounds; there are no more effective control options.

Step 5 - Establish BACT

The Permittee proposed a BACT emission limit of 0.089 lb/hr, as hydrogen sulfide, based on a rolling three-hour average. Based on its review of emission levels achieved by other state-of-the-art sulfur recovery plants, the Department determined that the Permittee's proposal represents BACT. The Department is not aware of any sulfur recovery plant that is subject to a more stringent emission limit for reduced sulfur compounds.

3. BACT for Nitrogen Oxides

Step 1 - Identify All Control Options

Identified control technologies and techniques for NO_x emissions include combustion modifications (low-NO_x burners and flue gas recirculation) and post-combustion control devices [selective catalytic reduction (SCR),

selective non-catalytic reduction (SNCR), and SCONO_x].

Step 2 - Eliminate Technically Infeasible Control Options

The Department concluded that the use of low-NO_x burners is the only technically feasible control option for the TGTU thermal oxidizer. Other combustion modifications, such as flue gas recirculation, which are designed to achieve NO_x emissions decreases by reducing flame temperature, are not compatible with the primary function of the thermal oxidizer (i.e., destruction of reduced sulfur compounds). Based on information available to the Department, none of the identified add-on control technologies has been demonstrated to be technically feasible for thermal oxidizers, and there are significant technical differences between the proposed thermal oxidizer and the combustion sources where each of these technologies has been demonstrated in practice.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The NO_x emission level demonstrated to be achievable with low-NO_x burners on TGTU thermal oxidizers is 0.06 lb/MMBtu heat input (HHV), based on a one-hour average. This control option has been proposed by the Permittee for the TGTU thermal oxidizer at the proposed refinery.

Step 4 - Evaluate More Effective Control Options

No technically feasible control options more effective than the option proposed by the applicant were identified by the Department.

Step 5 - Establish BACT

The Permittee proposed a NO_x emission limit of 0.06 lb/MMBtu heat input for the TGTU thermal oxidizer. Based on its review of emission levels achieved by other petroleum refinery TGTU thermal oxidizers, the Department determined that the Permittee's proposal represents BACT.

The Department has included in the proposed permit a NO_x emission limit of 0.06 lb/MMBtu heat input (HHV), based on a one-hour average.

D. BACT for Sulfur Pits

The Sulfur Recovery Plant will include two storage vessels for molten sulfur produced by the Sulfur Recovery Units. These vessels, called "sulfur pits," are potential sources of reduced sulfur compound emissions.

Steps 1-4

Control options for the Sulfur Pits are routing the sweep gas to a thermal oxidizer or to the front end of the Sulfur Recovery Units for recovery of the sulfur contained in the gas. Each of these options is technically feasible. Both options would achieve nearly 100 percent control of emissions of hydrogen sulfide and other reduced sulfur compounds. However, the first option would result in significant, adverse environmental impacts because essentially all of the sulfur contained in the sweep gas would be oxidized to sulfur dioxide. No adverse environmental impacts are associated with the second control option.

Step 5 - Establish BACT

In its initial permit application, the Permittee proposed to route the sweep gas from the Sulfur Pits to the Sulfur Recovery Plant Thermal Oxidizer. Based on further review of control techniques used by other state-of-the-art sulfur recovery plants, the Department determined that routing the sweep gas to the Sulfur Recovery Units for recovery of the sulfur is an environmentally preferable alternative. As a result, the Permittee revised its permit application to reflect this control strategy. The Department is not aware of any sulfur recovery plant that is subject to more stringent requirements for emissions of reduced sulfur compounds from sulfur pits, and concurs that this control strategy represents BACT. No emission limit is needed, because the sweep gas is considered a raw material that is fed to the Sulfur Recovery Units.

E. BACT for Sulfur Loading

The Sulfur Recovery Plant will include truck and rail car loading racks for molten sulfur produced by the Sulfur Recovery Units. These loading racks are potential sources of reduced sulfur compound emissions.

Steps 1-4

Control options for the sulfur loading racks include degassing the sulfur prior to loading and routing the displaced gases to a thermal oxidizer. Each of these options is technically feasible. The first option is considered a pollution prevention activity because the hydrogen sulfide removed from the molten sulfur is routed to the front end of the Sulfur Recovery Units for recovery as a salable product. This option has no adverse environmental impacts. The second option would result in significant, adverse environmental impacts because nearly all of the sulfur in the gases displaced during loading would be oxidized to sulfur dioxide.

Step 5 - Establish BACT

BACT for the sulfur loading racks is a requirement that the sulfur be degassed to a maximum hydrogen sulfide concentration of 15 parts per million by weight prior to loading.

F. BACT for Storage Tanks

As described in Sections II.P through II.S herein, the proposed refinery will include 62 large cylindrical tanks and six pressure spheres used to store feed stocks, process intermediates, and final products. Emissions from storage tanks, primarily VOC, occur as a result of displacement of headspace vapor during filling operations in the case of fixed roof or internal floating roof tanks, or from tank rim seals in the case of external floating roof tanks (i.e., working losses). To a lesser degree, diurnal temperature variations and solar heating cycles also result in VOC emissions from storage tanks (i.e., storage or “breathing” losses). With proposed BACT controls, estimated emissions associated with the storage tanks account for approximately seven percent of the facility-wide annual VOC emissions. Of this amount, about two-thirds is released from internal floating roof storage tanks (Group “B” Storage Tanks) for which the proposed BACT is collection of vapors in a closed vent system and control by a thermal oxidizer.

1. Volatile Organic Compounds

Step 1 - Identify All Control Options

Available VOC control options for petroleum liquid storage tanks include inherently less-polluting processes, control equipment designed to minimize vapor leakage from the tanks, end-of-pipe air pollution control equipment, and combinations thereof. The nominal requirements relating to control of VOC emissions from storage tanks are outlined in the petroleum refinery NESHAP regulation, 40 CFR 63 subpart CC, and the Hazardous Organic NESHAP (HON), 40 CFR 63 subpart G. The following control options are available for petroleum liquid storage tanks:

- Operating the vessel under pressure, such that it operates with no emissions;
- Routing vapors to a process or a fuel gas system via hard piping, such that the vessel operates with no emissions;
- External floating roof;
- Fixed roof with vapor collection by a closed vent system routed to a control device (e.g., thermal oxidizer, carbon adsorber);
- Fixed roof in combination with an internal floating roof; and
- Fixed roof in combination with an internal floating roof and with vapor collection in a closed vent system routed to a control device (e.g., thermal oxidizer, carbon adsorber).

Step 2 - Eliminate Technically Infeasible Control Options

The two most effective control options, operating the tank with no emissions either by operating under pressure or by routing all sweep gases to a process or a fuel gas system, are feasible only for tanks storing certain

petroleum liquids. Either of the two most effective control options would be considered an inherently less-polluting process configuration. The first is suitable only for materials, such as propane and butane, that are gases at atmospheric pressure. This control option is proposed by the Permittee for the six "Group 'D'" storage tanks. The second is feasible only for tanks storing petroleum liquids that are compatible with the process or fuel gas system into which the gases would be routed. This control option is proposed by the Permittee for the eight "Group 'A'" storage tanks, with gases routed to a compressor in the RFG system. For all remaining tanks, these control options are not considered technically feasible.

All other identified control options are technically feasible for all storage tanks.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

Storage tank control options, in order of decreasing overall control effectiveness, are presented below:

Process configurations with no emissions - As noted in the discussion of technical feasibility in Step 2, the Permittee has proposed for the Group "A" and Group "D" storage tanks process configurations that will result in the tanks operating effectively with no VOC emissions.

Fixed roof in combination with internal floating roof and with vapor collection in a closed vent system routed to a control device - This design incorporates a roof structure that floats on the surface of the stored liquid, with dual flexible seals along the edge of the roof. This design effectively eliminates working losses. As further control, the headspace between the floating roof and the top of the tank is filled with an inert "sweep" gas (e.g., nitrogen) which is vented under slight vacuum. The breathing losses that escape through tank penetrations and seals are carried with the sweep gas to an add-on control device such as a thermal oxidizer or a regenerative adsorption system. The Permittee has proposed this control option both for the 47 Group "B" storage tanks and for the Sour Water Tank. The Permittee has proposed to use a thermal oxidizer as the control device for the Group "B" storage tanks and a carbon adsorption system as the control device for the Sour Water Tank.

Internal floating roof and dual rim seals - This design is the same basic configuration as the previous option, but does not include a sweep gas routed to a control device. The Permittee has not proposed this control option for any storage tanks.

External floating roof with dual rim seals - This design is similar to the

internal floating roof configuration described above, but without the enclosed headspace. The floating roof and seals act to reduce volatilization losses. This control option has overall effectiveness approximately equivalent to that of the internal floating roof control option described immediately above. The external floating roof design is commonly accepted control technology for vessels storing liquids with relatively low volatility. The Permittee has not proposed this control option for any storage tanks.

Fixed roof with vapor collection by a closed vent system routed to a control device - This design omits any control equipment (e.g., floating roof) designed to minimize generation of VOC-laden vapors, instead relying only on an end-of-pipe air pollution control device. This configuration is not proposed by the Permittee for any storage tanks.

Step 4 - Evaluate More Effective Control Options

For the Group “A,” Group “B,” and Group “D” Storage Tanks and for the Sour Water Tank, the control option proposed as BACT by the Permittee is the top control option and no detailed evaluation of other control options is necessary.

Step 5 - Establish BACT

A number of tank types will be represented at the proposed refinery because specific designs are suitable for specific service categories, as shown in the Outside Battery Limits (OSBL) Storage Tank Listing provided in Section 2 of the permit application. The following sections summarize the selected BACT tank designs and emission control systems for each tank category:

Group “A” Storage Tanks:

The BACT control strategy proposed by the Permittee for the Group “A” Storage Tanks is as follows: Eight storage tanks at the proposed refinery will be of the pressurized dome roof configuration and will have a nitrogen gas blanket in contact with the liquid. The pressurized dome roof tanks are used to store products that may suffer reductions in quality if exposed to the oxygen present in ambient air. The nitrogen blanket does not create a continuous exhaust flow from the tank. Make-up nitrogen is bled into the dome headspace to balance losses, or to equalize pressure when the tank is drained. During normal tank operation, the vapor space of the tank (containing nitrogen and VOC) is discharged only during tank filling, and small breathing losses may occur during daily temperature swings.

The displaced VOC emissions from the pressurized dome roof tanks are captured and routed to a compression system. This unit compresses the storage tank vapors and inserts them into the RFG system for use in numerous refinery combustion sources. This capture/control technique has a control efficiency of essentially 100 percent.

The Department is not aware of any more stringent available control option. Therefore, it concurs with the Permittee's proposed BACT control strategy.

Group "B" Storage Tanks:

The BACT control strategy proposed by the Permittee for the Group "B" Storage Tanks is as follows: Forty-seven storage tanks will have an internal floating roof design, and will have the headspace above the floating roof vented to a thermal oxidizer. The thermal oxidizer will be designed to achieve a minimum of 99.9 percent VOC destruction efficiency.

The VOC BACT conditions in the proposed permit include minimum design standards for the internal floating roof tanks, based on those found in 40 CFR 63 subpart G (HON for storage vessels), and for the thermal oxidizer. The primary design requirements are a design VOC destruction efficiency of 99.9 percent at inlet VOC concentrations above 20,000 ppmv and a design outlet concentration of 20 ppmv at lower inlet concentrations. Other emission limitations for the thermal oxidizer are expressed as operational requirements (minimum temperature and maximum exhaust gas flow rate). This approach is consistent with BACT precedent and allows for streamlined monitoring (i.e., CAM is not applicable because continuous monitoring consistent with the units of the standard is specified). Refer to Section IV.F herein for a complete discussion of CAM applicability. The Tank Farm Thermal Oxidizer combustion chamber must be maintained at a temperature of least 1600 °F and the exhaust gas volumetric flow rate must be maintained below the rate that corresponds to a minimum residence time of 0.75 seconds. Continuous monitoring of thermal oxidizer combustion chamber temperature and exhaust gas volumetric flow rate are required, as well as annual inspections of the thermal oxidizer burner and monitoring systems.

The Department is not aware of any more stringent available control option. Thus, it concurs with the Permittee's proposed BACT control strategy.

Sour Water Tank:

The BACT control strategy proposed by the Permittee for the Sour Water

Tank is as follows: The Sour Water Tank will have an internal floating roof design. This tank will be equipped with suitable double seals at the perimeter and other roof penetrations meeting design specifications under 40 CFR 60 subpart Kb. In addition, the headspace from the tank will be routed to a carbon adsorption system comprising dual carbon canisters.

The Department is not aware of any more stringent available control option. Thus, it concurs with the Permittee's proposed BACT control strategy.

Group "D" Storage Tanks:

Six pressure vessels with zero emissions to the atmosphere are proposed to store high vapor pressure material such as LPG, natural gasoline, butane, etc. As pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere, these tanks are exempt from regulation under the petroleum refinery NESHAP pursuant to 40 CFR 63.641. Pressure vessels designed for zero emissions inherently constitute BACT for VOC emissions.

Group "E" Storage Tanks:

A single storage tank (T-42801) storing asphalt comprises the Group "E" Storage Tank category. This tank is subject to the requirements of 40 CFR 60 subpart UU. The vapor pressure of asphalt is below the thresholds for control requirements under 40 CFR 60 subpart Kb and 40 CFR 63 subpart CC. Therefore, no substantive NSPS or NESHAP requirements for VOC emissions apply to the tank. Due to the extremely low vapor pressure of asphalt, even at elevated storage temperatures, and the regulatory precedent, the proposed permit contains no additional tank design or control system requirements for VOC emissions from this tank.

Tank Degassing and Cleaning:

Elevated VOC emissions can occur during routine storage tank degassing and cleaning operations. South Coast Air Quality Management District (SCAQMD) Rule 1149 contains provisions for storage tank cleaning and degassing that are representative of BACT measures for Group "A", "B", and "C" storage tanks. Under the proposed BACT provisions, emissions from tanks opened to the atmosphere for cleaning or degassing must be controlled by using one of the following:

- Liquid balancing;
- Negative pressure displacement and subsequent incineration in an approved manner;
- Refrigerated condenser which reduces the vapor temperature to

- 100° F or lower; or
- Other approved control method or control equipment at least 90 percent efficient in controlling VOC emissions.

2. BACT for Particulate Matter

For most of the proposed refinery storage tanks, PM emissions are either zero or negligible, and BACT requirements beyond those specified for VOC are not warranted. Only the Group “E” Storage Tank, Asphalt Storage Tank T-42801, is a potential source of PM emissions and was included in the BACT analysis.

Steps 1 - 4

Pursuant to 40 CFR 60 subpart UU, § 60.472(c), Asphalt Storage Tank T-42801 is required to be operated with no visible emissions to the atmosphere, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for cleaning. No specific control technologies are prescribed.

A review of BACT guidance and precedent for asphalt storage tanks revealed limited data. A single guideline was identified. The Bay Area Air Quality Management District (BAAQMD) maintains a BACT guideline for asphalt storage tanks that specifies that exhaust gases be cooled to less than 120 °F and vented through a fiberglass or steel wool filter.⁵

Step 5 - Establish BACT

The BAAQMD BACT guideline provisions identified above, along with the NSPS requirement for zero opacity emissions, were selected as BACT for PM emissions from the asphalt storage tank and were incorporated into the draft permit.

G. BACT for Loading Racks

The proposed refinery will include loading racks for transferring gasoline and distillate products to rail cars and trucks. These are sources of VOC emissions.

Step 1 - Identify All Control Options

Identified control technologies for VOC emissions from loading racks include carbon adsorption, condensation, and incineration.

⁵See BAAQMD BACT Guideline Document No. 12.1, 11/8/91.

Step 2 - Eliminate Technically Infeasible Control Options

Each of the identified control technologies is technically feasible for application to the loading racks.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

Applied individually, the identified technologies have approximately equivalent control effectiveness capabilities. Each technology, when applied to the exhaust streams from the loading racks, is capable of achieving VOC control efficiencies in excess of 98 percent. The most effective control strategy involves the use of vapor recovery followed by incineration.

Step 4 - Evaluate More Effective Control Options

The Permittee has proposed as BACT for the gasoline product loading racks a vapor recovery system using carbon adsorption (i.e., a regenerative adsorption system) followed by a thermal oxidizer. This is the top control option for the gasoline product loading racks. Thus, no evaluation of alternative control options is necessary.

For the distillate product loading racks, the Permittee has proposed to use a thermal oxidizer. The use of a vapor recovery system followed by incineration is an available, technically feasible, and more effective VOC control option for the distillate product loading racks. The Department concludes that the configuration proposed by the Permittee represents BACT because the beneficial environmental impacts associated with the more stringent control option (i.e., improved VOC control effectiveness) are outweighed by the adverse economic impacts that would result. The rationale for this conclusion is presented in the following paragraphs.

The more stringent control option was evaluated by the Permittee, in its permit application, and by the Department. The evaluation included identification and comparison of the economic, environmental, and energy impacts of the proposed control option and the more stringent control option. Regenerative adsorption systems were used to represent the vapor recovery system technology in this analysis. It was assumed that two separate units, one for jet fuel and one for Diesel fuel, would be required.

Energy Impacts. In the more effective control option, the vapor recovery system would require steam for adsorbent regeneration and electrical input for functions such as air movement. These are insignificant adverse impacts. Used downstream of a vapor recovery system, the thermal oxidizer would be smaller and would use less fuel, which is an insignificant beneficial impact of the more effective control option. These offsetting and insignificant energy impacts were

not a factor in the decision.

Environmental Impacts. Assuming 98 percent control efficiency, the more stringent control option would reduce VOC emissions by about 9 tons per year. In addition, when used downstream of a vapor recovery system, the thermal oxidizer would be smaller and would use less fuel, thereby generating less NO_x and CO emissions. These are beneficial environmental impacts.

Economic Impacts. As documented in Table 6.7-2 of the permit application, the Permittee provided cost information for upgrading the distillate product loading racks to a control option utilizing vapor recovery systems followed by a thermal oxidizer. The Permittee's cost estimate, presented as an incremental evaluation of applying the thermal oxidizer in addition to the vapor recovery systems, indicates an incremental cost effectiveness of \$21,336 per ton.

In performing its evaluation of economic impacts of the alternative control options, the Department relied on the cost information provided by the Permittee, but made several adjustments to the values provided. First, the Department calculated the amortized capital costs using an equipment life of 15 years and a real interest rate of 7 percent. Second, the Department compared the cost of the more effective control option to the proposed control option, and did not consider the costs of the vapor recovery systems applied alone. (Because that control option would provide control effectiveness less than the proposed control option at greater cost.) The Department's revised cost information yields an estimated incremental cost effectiveness of approximately \$30,000 per ton of VOC emission reduction.

Step 5 - Establish BACT

In its initial permit application, the Permittee proposed a VOC BACT emission limit for gasoline and distillate product loading racks of 10 milligrams per liter loaded. The maximum VOC emission rate under the Permittee's proposed BACT was 507 tons per year.

Based on further review of emission levels achieved by other petroleum liquid loading operations, the Department determined that lower emission limits are achievable using a vapor recovery system in series with a thermal oxidizer to control VOC emissions from gasoline product loading racks, and using a thermal oxidizer to control VOC emissions from distillate product loading racks. The Permittee adjusted its BACT proposal to reflect these control strategies.

Based on the evaluations performed in Step 4, the Department made its BACT determinations for gasoline product loading racks and distillate product loading racks. The Department agrees that the Permittee's proposal represents BACT for VOC emissions from these sources. The Department is not aware of any gasoline loading racks or distillate loading racks are subject to more stringent VOC

emission limits. The maximum VOC emission rate under the proposed BACT is approximately 26 tons per year, a reduction of approximately 95 percent from the originally proposed BACT control strategy.

The primary emission limits established as BACT are the VOC emission limits from the rail car and truck loading rack thermal oxidizers. These limits are 1.25 pounds per million gallons of product loaded at the gasoline product loading racks, and 22.0 pounds per million gallons of product loaded at the distillate product loading racks. Each of these limits is based on a rolling three-hour average. Compliance with this emission limit is to be demonstrated through continuous monitoring of temperature pursuant to an approved CAM plan. In addition to the thermal oxidizer VOC emission limits, the permit includes numerous work practice and equipment design requirements representing BACT, such as vapor collection system pressure-vacuum vent design specifications; prohibition of loading non-vapor-tight cargo tanks; and acting to ensure that the vapor collection systems are fully functional for each cargo tank loading.

H. Wastewater Treatment Plant

The Wastewater Treatment Plant includes a spray dryer, a wastewater collection system comprising drain systems and sumps, and a wastewater treatment system comprising a group of tanks. The spray dryer will emit only particulate matter. The wastewater collection and treatment systems will emit primarily VOC.

1. BACT for Particulate Matter

For this analysis, PM₁₀ is defined to include filterable particulate matter as measured by EPA Reference Method 5.

Steps 1-4

The control strategy proposed by the applicant is the use of a fabric filter baghouse. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts. Other identified control technologies include electrostatic precipitators, wet scrubbers, and inertial separators.

Step 5 - Establish BACT

The proposed BACT emission limit is an exhaust gas concentration of 0.005 grains per dry standard cubic foot, based on a three-hour average, using a fabric filter baghouse. Compliance with this emission limit is to be demonstrated through initial and annual performance testing. The Department is not aware of any spray dryer that is subject to a more stringent PM emission limit.

2. **BACT for Volatile Organic Compounds**

Step 1 - Identify All Control Options

Identified control technologies for VOC emissions from wastewater collection and treatment include carbon adsorption, incineration, and condensation.

Step 2 - Eliminate Technically Infeasible Control Options

All of the identified control options are technically feasible for application to the wastewater collection and treatment systems.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

Carbon adsorption and incineration have approximately equivalent control effectiveness capabilities. Each technology, when applied to the exhaust streams from the wastewater collection and treatment systems, is capable of achieving VOC control efficiencies in excess of 98 percent. Condensation would be expected to have somewhat lower achievable control efficiencies when applied to the exhaust streams from the wastewater collection and treatment systems.

The Permittee has proposed as BACT for the wastewater treatment system (i.e., tanks) the use of closed-vent systems vented to a thermal oxidizer. The Permittee has proposed as BACT for the wastewater collection system (i.e., drain systems and sumps) the use of closed-vent systems vented to carbon canisters or a thermal oxidizer, depending on the location and design of the individual emission source.

Step 4 - Evaluate More Effective Control Options

Neither of the control technologies proposed by the applicant has significant, adverse energy, environmental, or economic impacts. Each technology has a slight adverse environmental impact, i.e., solid waste from a carbon adsorption system and collateral air pollutant impacts from an incinerator, but these impacts are not sufficient to warrant rejection as BACT.

Step 5 - Establish BACT

The Department is not aware of any petroleum refinery wastewater collection and treatment systems that are required to use emission controls that are more stringent than those proposed by the Permittee. The Department has determined that the control strategy proposed by the

Permittee represents BACT for VOC emissions from these systems.

The VOC BACT requirements for the wastewater collection and treatment systems are expressed as equipment design standards and operational requirements. This form of expression will ensure that the maximum achievable level of emission control is achieved under all operating conditions. Specifically, for carbon canisters used to control emissions from sumps, the draft permit requires the use of dual canisters in series, with requirements for monitoring to detect breakthrough and for replacement in the event of breakthrough. For the Wastewater Treatment Plant Thermal Oxidizer, the primary design requirements are a design VOC destruction efficiency of 99.9 percent at inlet VOC concentrations above 20,000 ppmv and a design outlet concentration of 20 ppmv at lower inlet concentrations. Other emission limitations for the thermal oxidizer are expressed as operational requirements (minimum temperature and maximum exhaust gas flow rate). This approach is consistent with BACT precedent and allows for streamlined monitoring (i.e., CAM is not applicable because continuous monitoring consistent with the units of the standard is specified). Refer to Section IV.F herein for a complete discussion of CAM applicability. The Wastewater Treatment Plant Thermal Oxidizer combustion chamber must be maintained at a temperature of least 1600 °F and the exhaust gas volumetric flow rate must be maintained below the rate that corresponds to a minimum residence time of 0.75 seconds. Continuous monitoring of thermal oxidizer combustion chamber temperature and exhaust gas volumetric flow rate are required, as well as annual inspections of the thermal oxidizer burner and monitoring systems.

I. Equipment Leaks

Section XXIV of Attachment “B” of the proposed permit contains requirements for equipment leaks. The proposed ACF refinery design includes piping for the purpose of distributing the liquid and gaseous materials among process units. This piping includes thousands of piping components such as valves, pumps, compressors, flanges, and screwed connectors. Minor emissions of hydrogen sulfide may also occur due to leaking components in H₂S service. Equipment component emissions are mostly related to “leakage” from rotary shaft seals, connection interfaces, valve stems, and similar points.

1. BACT for Volatile Organic Compounds

Step 1 - Identify All Control Options

BACT control strategies for VOC equipment leaks are generally based on comprehensive leak detection and repair (LDAR) programs. The baseline requirements for such programs are described under the new source

provisions of the petroleum refinery NESHAP (40 CFR 63 subpart CC) and the HON for equipment leaks (40 CFR 63 subpart H). Alternate, and in some cases more stringent, requirements for new refinery installations are provided in the “28 MID” program⁶ implemented in Texas and in Regulation 8, Rule 18 implemented by the Bay Area Air Quality Management District in California.

Equipment Specifications - Commercially proven equipment components with inherent leak-less design and construction features are available for refinery applications. These components reduce or preclude VOC emissions, regardless of the quality or frequency of LDAR activities. Available control options identified in the 28 MID program involving equipment specification or design include the following:

Pumps:

- Use of canned, magnetic drive, or diaphragm pumps not having external seals; or
- Use of pumps designed with double mechanical seals and a barrier fluid. The barrier fluid is at a higher pressure than the process or the fluid seal pot should be routed to a control device.

Dual mechanical seal pumps - This style of pump offers low seal leakage provided they are chosen and maintained properly. The TNRCC estimates that such equipment provides 75 percent reduction in VOC compared to simple mechanical seals (TNRCC, Regulations Governing Equipment Leaks, 11/98).

Magnetic Drive Pumps - In a magnetic-drive centrifugal pump type, there is no direct coupling between the drive and the pump casing, and consequently no rotating shaft seal. The pump is driven by magnetic coupling of strong permanent magnets attached to the drive motor and similar permanent magnets incorporated into the impeller of the pump. The only connection is by way of the magnet flux passing through the magnetic permeable casing of the pump. Fluid being pumped is totally contained within the pump chamber, so that assumed control efficiency is 100 percent (TNRCC, Regulations Governing Equipment Leaks, 11/98).

Valves:

Selection of diaphragm valves or bellows valves with the bellows welded to both the bonnet and stem.

⁶See Texas Natural Resource Conservation Commission (TNRCC) Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives. October 2000.

Flanges and other Connectors:

Installation of piping connections that are welded around the complete circumference such that the joint cannot be disassembled by unbolting or unscrewing the components.

Relief Valves:

Routing of relief valve vents to an operating control device or use of rupture disks with a pressure gauge between a valve and the disk to monitor disk integrity.

Compressors:

Use of compressors designed with enclosed distance pieces and venting of the crankcase to a control device.

The above mentioned equipment designs can result in VOC control efficiency for the particular components of 100 percent assuming the device is functioning as intended. Alternatively, process equipment with a rotating shaft incorporating a double mechanical seal system without barrier fluid affords a control efficiency of approximately 75 percent. For certain equipment categories, applicable requirements also specify leak prevention design features. For example, compressors are required to include a barrier fluid system, and sampling connecting systems are required to be equipped with a closed-purge system routing the fluids back to the process or to a control device.

LDAR Program - The primary control option that has been deemed BACT for equipment leaks in prior determinations is an LDAR program. Such programs are also stipulated as mandatory requirements for new major sources of HAPs under the petroleum refinery NESHAP (40 CFR Part 63, subpart CC), which requires that sources comply with the provisions of the HON for equipment leaks (40 CFR 63 subpart H). An acceptable LDAR program includes suitable definition of a “leaking” component threshold concentration, as measured at the potential leak interface. In the HON subpart H, process equipment potentially present at petroleum refineries are grouped into the following categories:

- Pumps in light liquid service;
- Compressors;
- Pressure relief devices in gas/vapor service;
- Sampling connection systems;
- Open-ended valves or lines;
- Valves in gas/vapor service and in light liquid service;
- Pumps, valves, connectors, and agitators in heavy liquid service;

- Instrumentation systems;
- Pressure relief devices in liquid service;
- Surge control vessels and bottoms receivers; and
- Closed-vent systems and control devices.

For BACT purposes, the LDAR program must encompass all components that contain or convey VOC-containing fluids, while only equipment contacting fluids that meet specific HAP concentration criteria are subject to the NESHAP regulations. For each component category, leak detection procedures and test frequencies are defined in regulations or permit precedents that include both visual and instrumental inspections. If leaks are apparent through visible, audible, or olfactory means, the equipment must be repaired. If certain threshold VOC concentrations at the possible leak interface are surpassed during instrumental inspections (by EPA Reference Method 21 in appendix A to 40 CFR part 60), the equipment is also considered to be leaking and must be repaired.

New sources located in non-attainment areas and subject to the Lowest Achievable Emission Rate (LAER) requirements have adopted leak detection concentrations that are lower than those specified in applicable NESHAP standards. Examples of such determinations in California and Texas are documented in Table 6.5-1 of the Arizona Clean Fuels permit application. Generally, operating cost factors favor a lower leak detection definition since the value of lost product or intermediates due to a leak exceeds the projected cost of LDAR for those components. At very low leak definition levels, however, diminishing returns apply as less VOC is leaking when concentration is low, and the cost per unit VOC abated escalates dramatically as a large portion of the refinery components (even if recently replaced) may be deemed to be leaking.

Widely accepted BACT leak definition thresholds documented in the Arizona Clean Fuels permit application include pump and compressor seals at 2,000 ppmv, and valves and connectors at 500 ppmv. However, recent permits have specified more stringent leak detection definitions in some cases. A leak definition of 500 ppmv has been applied to all components in some permits, including pumps and compressors. This threshold concentration (i.e., leak definition) coincides with that stipulated in the 28 MID program for VOC emission reduction from component leakage.

In its review of LDAR program elements in various permits and regulations applicable to petroleum refineries, the Department identified one regulation (Bay Area Air Quality Management District, Regulation 8, Rule 18) that specifies a 100 ppmv leak definition for valves and connectors in gas/vapor and light liquid service. The Department also identified this rule as including limits, for some types of components, on

the refinery-wide percentage of components for which a delay in repair is allowed. In these respects, the Bay Area regulation is more stringent than other LDAR programs that do not include such provisions.

In the NESHAP program, each piece of equipment is monitored on a specified frequency (weekly, monthly, quarterly, and/or annually) and repaired within a specified timeframe after a leak is detected. Alternative standards provide the facility an incentive to demonstrate that the portion of “leaking” valves, pumps, etc. is not greater than a given percentage of the facility population.

Step 2 - Eliminate Technically Infeasible Control Options

Process equipment options that can essentially eliminate fugitive VOC emissions for all instances at the proposed refinery were deemed infeasible or cost prohibitive. However, equipment options such as seal-less magnetic drive pumps and bellows-seal valves are available and technically feasible for many of the duties involved in the refinery design. There are more complex options that were viewed as impractical and cost-prohibitive due the large quantity of pumps and compressors that would be involved. For example, the capture and routing of vapor emissions from all facility pumps and compressors to one or more control devices would be impractical. Such control would involve the addition of an enormous quantity of additional vapor piping and equipment, which would constitute numerous additional fugitive emission sources.

The welding of flange edges and the elimination of piping connections are not feasible in cases where bolted flange connections are necessary. These include instances where access is necessary for maintenance, to facilitate equipment disassembly for inspection and maintenance, or to accommodate normal thermal expansion. Also, bolted flanges are necessary when vibration isolators or stress relief devices are needed on a pipe run. Because of cost considerations, flanges are used only when required for such purposes.

Selection of seal-less pumps is technically feasible for a limited number of situations. However, magnetic drive pumps or other seal-less designs are not commercially available across all ranges of flow and pressures encountered. Primarily, this is because the power transferred from the drive to the pump impeller is limited by the permeability of the pump casing to magnetic fields and the strength of the magnetic field itself. Also, a large portion of the pumps in refineries are driven by high-pressure steam impellers, which limits the availability of the magnetic-drive or seal-less pump option.

Another design selection that would reduce fugitive component VOC

emissions includes the use of bellows-seal valves. Bellows-seal valves that are weld-sealed at the top and bottom of the bellows have been stipulated in new source permits by the South Coast Air Quality Management District for new refinery piping components up to and including 8 inches in diameter.

Because seal-less pumps and bellows-seal valves are commercially proven and available for a range of refinery applications, these equipment design options were considered in the BACT economic analysis.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The technically feasible control strategies, in order of decreasing stringency, are as follows:

- Full implementation of seal-less pumps (e.g., diaphragm, canned, or magnetic drive centrifugal pumps) and seal-less/leakless valves (e.g., welded bonnet bellows and diaphragm valves); HON subpart H and 28 MID equipment design specifications and LDAR programs; and 500 ppmv leak definition for all components.
- HON subpart H and 28 MID equipment design specifications and LDAR programs; limits on percent leaking components; 100 ppmv leak definition for valves and connectors in gas/vapor and light liquid service; and 500 ppmv leak definition for all other components.
- HON subpart H equipment design specifications and LDAR programs; plus leak definitions as required by applicable regulations for all components.

Step 4 - Evaluate More Effective Control Options

Seal-less pumps and bellows seal valves are commercially available for many of the services encountered in the proposed refinery design. Cost effectiveness varies depending on the pump size and type of fluid service category. Tables 6.5-2 through 6.5-6 of the Arizona Clean Fuels permit application present control cost estimates and BACT cost effectiveness for multiple scenarios of seal-less pump and bellows seal valve implementations.

In the Permittee's BACT analysis, the number of pumps or valves in a given service category was estimated, along with an average pump volume capacity. On this basis, the cost per ton abated ratio was determined for the two equipment options to provide a comparative cost effectiveness for pumps and valves in a given service category. Because both magnetic-drive pumps and bellows-seal valves offer nearly 100 percent

control efficiency, it was conservatively assumed that all of the VOC emissions attributed to the baseline pump and valve option would be abated.

Tables 6.5-2 and 6.5-3 in the permit application document that the implementation of magnetic drive pumps for any particular service category is not economically reasonable when compared to the beneficial environmental impacts that would result. The Permittee's analysis shows that the use of 242 magnetic-drive pumps (approximately three-fourths of the refinery-wide pump count) would have an annualized cost of over \$700,000 and would reduce VOC emissions by 5.1 tons per year compared to dual mechanical seal pumps. This yields an incremental cost effectiveness of approximately \$140,000 per ton of VOC. The Department's revised economic impacts analysis, which uses less conservative emission estimation methodologies, indicates that refinery-wide VOC emissions from pumps in VOC service will be only 2.6 tons per year. Using the Department's emission estimates, the incremental cost effectiveness of requiring magnetic-drive pumps would be well in excess of \$300,000 per ton of VOC emission reduction.

The results of the Permittee's economic impacts analysis for bellows-seal valves, provided in Tables 6.5-4 through 6.5-6 of the permit application, show that this measure also is economically unreasonable for abatement of VOC emissions. This analysis shows that the use of 15,938 bellows-seal valves (approximately half of the refinery-wide valve count) would have an annualized cost of over \$11 million and would reduce emissions by 77.9 tons per year compared to conventional valves. This yields an incremental cost effectiveness of approximately \$140,000 per ton. The Department's revised economic impacts analysis, which uses less conservative emission estimation methodologies, indicates that refinery-wide VOC emissions from valves in VOC service will be only 1.5 tons per year. Using the Department's emission estimates, the incremental cost effectiveness of requiring bellows-seal valves would be well in excess of \$1 million per ton of VOC emission reduction.

Step 5 - Establish BACT

A recent U.S. EPA policy memorandum concluded that the requirements of the HON for equipment leaks (40 CFR 63 subpart H) constituted LAER and presumptive BACT for VOC emissions from refinery equipment leaks.⁷ In that memorandum, the U.S. EPA stated:

⁷ See January 19, 2001 memorandum from J.S. Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to Air Division Directors, U.S. EPA Regions I-X. "BACT and LAER for emissions of NO_x and VOC at Tier 2/Gasoline Sulfur Refinery Projects."

“After a review of the available information, it is EPA's conclusion that for VOC emissions from hydrotreaters and hydrogen units, at both large and small refiners, compliance with the Hazardous Organic National Emission Standards for Hazardous Air Pollutants (HON) (40 CFR Part 63 Subpart H) represents BACT. This is the most stringent control level achievable for VOCs from these units. In concluding that compliance with the HON represents BACT, EPA considered the incremental and average cost of the control strategy as well as any associated energy and environmental impacts. No adverse impacts were found to be associated with the most effective control option. Consequently, it was determined to be BACT. The control option represents the most stringent control level achieved or contained in a SIP, it therefore also represents LAER for those units.”

The substantive requirements of the HON Subpart H LDAR program are applicable to the proposed refinery. (See Sections IV.C.5 and IV.C.7 herein for additional discussion.) Therefore, these requirements were deemed representative of the BACT baseline for VOC emissions from equipment leaks. These requirements were augmented with more stringent leak definitions (100 ppmv for valves and connectors in gas/vapor and light liquid service, 500 ppmv for all other components) and with the equipment design specification provisions from the 28 MID program, as noted below, to reflect BACT precedent.

General:

- All piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.
- Underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.
- To the extent that good engineering practice will permit, valves and piping connections shall be located such that they are reasonably accessible for leak-checking during plant operation. Construction of new and reworked piping valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

Connectors:

For equipment in gas/vapor service or in light liquid service, all piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inches in diameter.

Pumps and Compressors:

All pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These may include, but are not limited to, dual pump seals with barrier fluid at higher pressure than process pressure; seals degassing to vent control systems; or seals equipped with an automatic seal failure detection and alarm system. Submerged or seal-less pumps may be used to satisfy this requirement.

Valves:

To the extent practical, considering operability and safety factors, the Permittee shall install seal-less or leak-less valves including, but not limited to, welded bonnet bellow and diaphragm valves.

2. BACT for Hydrogen Sulfide

Steps 1 - 4

Available technologies for H₂S equipment leak BACT include leak-less equipment design, LDAR, and continuous instrumental ambient concentration monitoring. Due to the toxicity of H₂S, leak-less equipment design is inherent to units in H₂S service. Worker exposure and process safety regulations, such as the Process Safety Management (PSM) standards administered by the Occupational Safety and Health Administration (OSHA), constrain equipment design and leak related emissions to a greater extent than identified BACT precedents.

In its permit application, the applicant proposed BACT for H₂S equipment leaks mirroring the LDAR requirements for VOC and organic HAP emissions, but with more stringent leak definitions. From the Department's review, no refinery permits were found requiring instrumental H₂S leak monitoring. However, several refinery permits were reviewed that require instrumental H₂S fence line or area monitoring in conjunction with olfactory H₂S LDAR. Generally, the Department determined that Texas refinery permits require instrumental H₂S area monitoring and California refinery permits require instrumental H₂S monitoring at the facility fence line. Examples of these permit conditions are provided below.

The following example is from Permit Number 9868A (PSD-TX-102M4) for Phillips Petroleum in Borger, Texas:

There shall be 45 H₂S monitors placed throughout the sulfur recovery, amine regeneration, and sour water stripping areas. These monitors shall be arranged in such a way that coverage is provided for wind directions varying through 360 degrees. The existing monitors shall be set to alarm at a concentration of 10 ppmv and shall alarm in the control room.

The following example is from the Bay Area Air Quality Management District, *Manual of Procedures*, Volume VI, and is referenced and required under Permit Number A0011 for Shell Oil Products in Martinez, California:

[T]he person responsible for emissions shall provide recording instrumentation at not less than three sites chosen to monitor the ambient air in the area surrounding the emission source and at least one meteorological station to record wind speed and direction. Additional instruments may be required in specific cases where necessary to meet the intent of the appropriate section. The instruments shall be sufficient in number to give reasonable assurance that any ground level limits exceeding the applicable standards will be detected. All analytical instrumentation shall be capable of detecting ground level concentrations which exceed the allowable limits. All instrumentation shall be continuous and equipped with either a strip chart recorder or an electronic data recorder which archives data at averaging intervals not to exceed one minute.

The instruments shall be installed and operated in locations which adequately represent maximum ground level concentrations of the measured air pollutants. Sites will be chosen to intercept most frequent ground level maximum concentrations, but in conformance with Regulation 1-510. Proper siting will be taken to require that a preponderant downwind exposure over the calendar year be accumulated by the instruments of given network, during their hours of operation. Downwind exposure exists when the mean wind direction lies in the arc within 22.5 degrees of a direct line from source to monitor. The effective source height and the prevalent stability class associated with the most frequent wind directions are used to calculate the most probable distances for maximum ground level concentrations. A station may be placed at or within the property line if the location is otherwise acceptable and provided that the person responsible for the stations agrees in writing that such location shall, for the purposes of District requirements, be deemed to be off the property from which the emissions occur. The wind measuring site (or sites) shall be located within the general area encompassed by the source and the ground level monitors. In any case, they must comply with the latest edition of the Bay Area Air Quality Management District Meteorological Monitoring Guidance. Final approval of the siting of ground level monitors and meteorological instrumentation shall be with the [District].

Step 5 - Establish BACT

From available BACT precedent data, continuous fenceline ambient monitoring combined with olfactory LDAR was selected as BACT for H₂S equipment leaks. The proposed permit stipulates that an H₂S ambient monitoring plan be developed and submitted to the Department for

approval. In summary, the proposed BACT conditions for H₂S equipment leaks are as follows:

- Install, certify, operate, and maintain a network of H₂S concentration monitors at the facility boundary. Monitors shall be set to alarm at a concentration no higher than 0.03 ppmv.
- Submittal of an H₂S monitoring plan.
- Audio, olfactory, and visual checks for H₂S leaks within each operating area containing equipment in H₂S service once per shift.
- Corrective action shall be taken immediately, and no later than one hour upon detection of a leak

In addition to the fence-line ambient monitoring required as BACT, the Department notes that the proposed refinery also will be subject to the Process Hazard Analysis requirements under 29 CFR 1910.119(e). Specifically, pursuant to 29 CFR 1910.119(e)(3)(iii), the analysis is required to address:

“Engineering and administrative controls applicable to the hazards and their interrelationships such as appropriate application of detection methodologies to provide early warning of releases. (Acceptable detection methods might include process monitoring and control instrumentation with alarms, and detection hardware such as hydrocarbon sensors.)”

In order to meet these worker safety and health requirements, the proposed refinery will be required to implement an on-site H₂S concentration monitoring program, or equivalent, within the process unit areas containing equipment in H₂S service. This monitoring will be in addition to that required by the proposed air quality permit.

J. Catalyst Regenerators

As described in Section III.M herein, the Catalytic Reforming Unit Catalyst Regenerator and the Butane Conversion Unit Catalyst Regenerator will emit small quantities of CO and NO_x. The Permittee has indicated that the CO and NO_x emissions from each catalyst regenerator are 0.50 and 0.82 lbs per hour, respectively. These values are based on design maximum exhaust gas flow rates and a conservatively estimated concentration of 200 ppmv for each pollutant. Annual emissions are calculated assuming the hourly emission rate for 8,760 hours per year.

Steps 1-4

The Department is not aware of any process improvements that would be provided for reductions in CO and NO_x emissions from the catalyst regenerators. Any end-

of-pipe control technology, including SCR and oxidation catalyst, could be applied. However, due to the extremely small size of these emission units, any such application would involve unreasonable, adverse economic impacts and minimal environmental benefit. The uncontrolled rates of CO and NO_x emissions from the catalyst regenerators are similar in magnitude to those from a gas-fired heater or boiler with a capacity of approximately 4 MMBtu/hr. Also, the catalyst regenerator exhaust gas exit temperature is less than 200 °F, so the gas would have to be reheated in order to allow the use of SCR or oxidation catalyst. Based on knowledge of BACT analyses for combustion sources in this size range, the Department expects that the average cost effectiveness of applying these control technologies would be approximately \$10,000 per ton of pollutant controlled. In light of the adverse economic impacts and the minimal environmental benefit that would result, the Department does not consider any end-of-pipe control technology to represent BACT for CO and NO_x emissions from the catalyst regenerators.

Step 5 - Establish BACT

The Permittee has proposed CO and NO_x BACT emission limits of 0.50 lb per hour and 0.82 lb per hour, respectively. These emission limits are based on an exhaust gas concentration of 200 ppmv for each pollutant. The Department concurs with these proposed emission limits, and is not aware of any similar emission units achieving more stringent emission limits.

K. Petroleum Coke Storage and Handling

The handling and storage of petroleum coke, from removal of coke from the coke drums in the Delayed Coking Unit to the loading of coke into rail cars for transport off-site, are potential sources of particulate matter (dust) emissions.

Step 1 - Identify All Control Options

The control technologies that can be used to control particulate matter emissions from the coke handling operations are:

- Enclosures vented to fabric filter baghouses; and
- Wetting of the material to reduce the generation of dust.

Step 2 - Eliminate Technically Infeasible Control Options

Both identified control options are technically feasible for all petroleum coke storage and handling operations.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

Enclosures with fabric filter baghouses comprise the top control option and wetting is the second-ranked control option.

Step 4 - Evaluate More Effective Control Options

For the coke silo, the Permittee has proposed as BACT the use of a fabric filter baghouse designed so that the exhaust particulate matter concentration does not exceed 0.005 grains per dry standard cubic foot (gr/dscf). The applicant also provided cost information for baghouses designed to achieve particulate matter concentrations of 0.002 and 0.003 gr/dscf indicating that these more stringent levels would result in costs of \$10,000 or more per ton of incremental particulate matter reduction. The Department concurs that these costs would represent unwarranted, adverse economic impacts. The Department also notes that the proposed limit on particulate matter concentration is more stringent than the most stringent identified equipment specification for fabric filter baghouses on material handling systems. For these reasons, the Department concurs that the applicant's proposed design specification of 0.005 gr/dscf represents BACT.

For other coke handling operations, the Permittee evaluated the use of a total enclosure of the coker pit in conjunction with a closed-vent system and baghouse. Based on information provided by the Permittee, the annualized cost of this control option would be in excess of \$600,000 per year. These costs are unreasonable, given the very low emissions from these activities. The Permittee proposed as BACT the use of wet suppression for these operations. The Department concurs that this technology selection represents BACT for these operations.

Step 5 - Establish BACT

For the coke silo fabric filter baghouse, in addition to the particulate matter concentration limit of 0.005 gr/dscf, based on a three-hour average, the Department is imposing a visible emissions standard of zero opacity. This limitation will provide a more readily enforceable emission standard representing BACT, and will also ensure that the BACT emission limits for the proposed refinery are as stringent as the most stringent limits identified at other comparable facilities.

For other coke handling operations, the Department agrees with the applicant's proposed combination of work practices and equipment design requirements representing BACT. The specific requirements include a minimum moisture level of 12 percent in coke in all handling operations; a requirement for a building with flaps enclosing the rail car loading operations; and a requirement for walls surrounding all other coke handling operations.

L. Cooling Tower

The proposed refinery will require a continual supply of cooled water for heat exchangers, condensers, and other process units. This cooled water will be supplied from a forced-draft, wetted-media type cooling tower. This unit circulates warm “return” water through a media that promotes air/water contact and subsequent cooling by evaporation. This type of cooling tower is a source of particulate matter and VOC emissions.

Particulate matter is emitted from wet cooling towers due to the presence of suspended and dissolved solids in water droplets that drift from the cooling tower. As a droplet that drifts from the tower evaporates, the dissolved solids present in the droplet agglomerate into a single particle. The size of the resulting particle depends on the size of the droplet, the mass of the dissolved solids present in the droplet, and the density of the resulting particle.

VOC emissions occur due to evaporation of volatile organic compounds that may be present in the cooling water due to leaks in heat exchangers. As cooling water passes through one side of a water-cooled heat exchanger, if the water side of the exchanger is maintained at a lower pressure than the hydrocarbon fluid side of the exchanger, small amounts of hydrocarbon may leak to the water side.

1. BACT for Particulate Matter

Step 1 - Identify All Control Options

Two particulate matter control options were identified for the proposed cooling tower:

- Replacement of the wet cooling tower with a dry cooling tower; and
- Drift eliminators.

A dry cooling tower is an inherently less-polluting alternative to a wet cooling tower. This type of cooling tower circulates the process water through a large bank of radiator coils. These coils are cooled by forced flow of ambient air on the outer finned surfaces of the radiator. Ambient airflow is driven by very large axial propeller fans, typically located below the radiator bank, so that the air is blown upward through the radiator and the warmer air exits the top of the tower. Because there is no contact between the water and the ambient air, and thus no opportunity for drift, a dry cooling tower would not be a source of particulate matter emissions.

Drift eliminators are located perpendicular to the air flow and are designed to collect and remove condensed water droplets from the air stream. Changes of direction of the air flow passing through the eliminator promotes removal of droplets by coagulation and impaction on the eliminator surfaces. Particulate matter emissions are thus minimized as

drift is minimized.

Step 2 - Eliminate Technically Infeasible Control Options

The performance of dry cooling towers is limited by the ambient dry-bulb temperature rather than ambient wet-bulb temperature. Based on information provided by the Permittee, the return cooling water will arrive at the cooling tower at a design temperature of 102.6 °F and is to be cooled to a design temperature of 85 °F. The design cooling water temperature cannot be achieved using a dry cooling tower because the design dry-bulb temperature at the proposed site is in excess of 100 °F. Therefore, this control option is technically infeasible.

Steps 3-5

The only identified, technically feasible control option is the use of high-efficiency drift eliminators in conjunction with the proposed wet cooling tower. There are no significant environmental, energy, or economic impacts that would affect the determination of BACT.

The Permittee proposed as BACT the use of drift eliminators with a vendor-guaranteed maximum total liquid drift of 0.0005 percent of the circulating water flow rate. This is equivalent to the most stringent identified equipment specification for wet cooling towers. The Department concurs that this proposal represents BACT.

2. BACT for Volatile Organic Compounds

Step 1 - Identify All Control Options

Three VOC control options were identified for the proposed cooling tower:

- Replacement of the wet cooling tower with a dry cooling tower;
- Replacement of the direct-contact wet cooling tower with an indirect-contact wet cooling tower; and
- Heat exchanger leak detection and repair.

A dry cooling tower is an inherently less-polluting alternative to a wet cooling tower as described above, in Section V.L.1.

An indirect-contact cooling tower would use a sealed bank of exchanger tubes, bathed in an internally-circulating water cascade, to cool the process water. Because there is no contact between the process cooling water and the ambient air, and thus no opportunity for evaporation, an indirect-contact cooling tower would not be a source of VOC emissions.

A heat exchanger leak detection and repair program for water-cooled heat exchangers would involve monitoring cooling water for the presence of hydrocarbons, and detecting and repairing leaks when hydrocarbons are found. In some instances, suitable control may include installation of hydrocarbon detectors in the exit water downstream of the exchanger to identify leaking units. In addition, this measure would include systematic inspection, preventive maintenance, and repair programs to avoid leakage. This latter function can include routine replacement of seals, exchanger cleaning, and pressure testing of exchanger vessels.

Step 2 - Eliminate Technically Infeasible Control Options

A dry cooling tower is a technically infeasible control option for the reasons described in Section V.L.1.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The top control option is the use of an indirect-contact cooling tower rather than a direct-contact cooling tower. The other control option is the implementation of a heat exchanger leak detection and repair program.

Step 4 - Evaluate More Effective Control Options

An indirect-contact cooling tower design would encounter a significant energy penalty due to increased pumping requirements; reduced overall temperature differential for heat rejection from the process cooling water; and reduced heat transfer efficiency due to the presence of heat exchanger tube material and tube surface water film. Adverse economic impacts of this control option include the costs associated with the energy penalty; costs of water treatment for the added external water loop; and incremental capital and operating costs of the indirect-contact cooling tower in excess of those associated with the direct-contact cooling tower design. Based on information provided by the Permittee, the incremental cost of this control option is approximately \$20,000 per ton of VOC emission reduction. The Department has determined that this is an unreasonable, adverse economic impact. Due to the adverse energy and economic impacts of the more stringent control option, and its comparatively insignificant environmental benefits, the Department agrees with the Permittee's proposal that implementation of a heat exchanger leak detection and repair program represents BACT for the wet cooling tower.

Step 5 - Establish BACT

It should be noted that emission testing is not feasible for wet cooling

towers due to exhaust characteristics, so the BACT determination is expressed as a work practice requirement rather than an emission limit.

The required work practice (i.e., heat exchanger leak detection and repair program) requires application of hydrocarbon detectors at the return water outlet from one or a group of process heat exchangers, along with a systematic program of leak inspections and prompt repairs, consistent with the provisions of the SOCOMI NESHAP.

M. Internal Combustion Engines

The proposed refinery will include three reciprocating, lean-burn, compression-ignition internal combustion engines fired with Diesel fuel. These will include a 1500-horsepower engine, which will be used to drive an emergency electrical generator, and two 750-horsepower engines, which will be used to drive fire water pumps. Each engine will be permitted to operate for a maximum of 200 hours per year, but actual operation is expected to be considerably less.

The proposed compression-ignition internal combustion engines are generally similar to engines that are regulated as non-road mobile sources under 40 CFR part 89. These non-road engine emission standards will not apply to the engines at the proposed refinery because the engines will remain at the refinery site for more than 12 months. Notwithstanding this difference in regulatory applicability, the air pollution control techniques for compression-ignition engines such as those at the proposed refinery are generally driven by the emission standards for mobile sources. The mobile source emission regulations, unlike the BACT requirement for stationary sources, is technology-forcing; the current regulations establish emission standards that must be achieved by engines sold in the future and that are much more stringent than the standards that must be achieved today. For example, if the proposed refinery were operating today (in 2004) and required the temporary use of a skid-mounted, 1500-horsepower electrical generator, that engine would likely be compliant with the Tier 1 emission standards for non-road, compression-ignition engines. These emission standards apply to model year 2000 and later engines and include a NO_x emission limit of 0.015 lb per brake horsepower-hour engine output. The recently promulgated Tier 4 emission standards, which apply to model year 2011 and later engines, include a NO_x emission limit of 0.0011 lb per brake horsepower-hour engine output. This represents a 93 percent reduction in allowable emission levels, based on the expectations of U.S. EPA's Office of Mobile Sources with regard to the technological advancements that will be made by the engine manufacturing industry over the next several years.

The Department cannot make its BACT determinations for the internal combustion engines at the proposed refinery using the approach that U.S. EPA's Office of Mobile Sources uses, relying on expectations of future technological advancements, due to differences in the statutory requirements. However, the

Department can and does rely on the continued research of U.S. EPA's Office of Mobile Sources with regard to recent technological advancements for control of emissions from non-road, compression-ignition engines.

1. BACT for Sulfur Dioxide

Steps 1-4

The only control option identified for the internal combustion engines is the use of low-sulfur Diesel fuel. This control option is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5 - Establish BACT

In its initial permit application, the Permittee proposed a Diesel fuel sulfur content of 0.5 percent by weight as the BACT emission limit for SO₂ from compression-ignition internal combustion engines.

Based on a review of available information characterizing availability of lower sulfur fuels, including representations made by the applicant with regard to the fuels that will be produced at the proposed refinery, the Department determined that a Diesel fuel sulfur content limit of 15 parts per million by weight (ppmw) (equivalent to 0.0015 percent by weight) is achievable. The Permittee adjusted its BACT proposal to reflect this value as the proposed emission limit representing BACT for SO₂ emissions.

The Department concurs that this proposal represents BACT for SO₂ emissions from compression-ignition internal combustion engines. The Department is not aware of any similar sources that are subject to more stringent SO₂ emission limits.

2. BACT for Nitrogen Oxides

Step 1 - Identify All Control Options

Identified control technologies and techniques for NO_x emissions from compression-ignition engines include the following:

- Fuel injection rate shaping and multiple fuel injections, which typically utilize electronically-controlled fuel injection systems that vary the fuel injection rate and method according to engine load and other operating conditions. Lower NO_x emissions are achieved by initially limiting the rapid increase in temperature and pressure in the cylinder, postponing injection of most of the fuel

- until an established flame exists.
- Charge air cooling, which typically involves lowering the intake manifold temperature using an air-to-air heat exchanger, or aftercooler, located downstream of a turbocharger. Lower NO_x emissions are achieved by reducing the peak combustion temperature.
 - Injection timing retard, also called ignition timing retard, which involves delaying the fuel injection point in each engine cycle such that the heat release from fuel combustion occurs during the cylinder expansion. Lower NO_x emissions are achieved by reducing the peak combustion temperature.
 - Exhaust gas recirculation, which involves retaining or re-introducing a fraction of the exhaust gases. Lower NO_x emissions are achieved by reducing the peak combustion temperature and by reducing the amount of available molecular oxygen.
 - Lean-NO_x catalyst technology, which typically involves the injection of Diesel fuel into the exhaust gas upstream of a zeolite catalyst. The catalyst adsorbs hydrocarbons from the reductant, creating a locally oxygen-poor region in which reduction of NO_x to N₂ and O₂ is promoted.
 - NO_x adsorber technology, which typically utilize alkali or alkaline earth metal catalysts to adsorb NO_x on the catalyst surface under the fuel-lean and oxygen-rich conditions typical of Diesel engine exhaust. Periodically, the catalyst bed is subjected to fuel-rich exhaust in order to desorb the NO_x and regenerate the catalyst. The desorbed NO_x is catalytically reduced over a second catalyst, typically platinum and rhodium. The periodic regeneration step, which may occur as frequently as every 15 seconds or as infrequently as every several minutes during engine operation, comprises only a small fraction of total operating time. The fuel-rich exhaust conditions required for the regeneration step may be achieved by periodic changes in engine cycle operation, using fuel injection rate shaping systems as described above.
 - Selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and SCONO_x, all of which are described in Section V.B.3 herein.

Step 2 - Eliminate Technically Infeasible Control Options

Lean-NO_x catalyst technology, NO_x adsorber technology, and SCONO_x have not been demonstrated to function efficiently on stationary, compression-ignition engines or on sources with similar exhaust gas characteristics. Therefore, these technologies are not considered technically feasible options for controlling NO_x emissions from the internal combustion engines at the proposed refinery.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The second-ranked control option for NO_x emissions comprises the use of internal combustion engines certified by the engine manufacturer to meet the emission standards for model year 2006 and later non-road, compression-ignition engines, as codified at 40 CFR § 89.112. For the emergency generator engine, with a rated power output in excess of 560 kilowatts, the relevant emission standards are known as the “Tier 2” standards and include a limit of 6.4 grams of combined NO_x plus nonmethane hydrocarbons per kilowatt-hour of output. For the emergency fire water pump engines, each with a rated power output between 130 and 560 kilowatts, the relevant emission standards are known as the “Tier 3” standards and include a limit of 4.0 grams of combined NO_x plus nonmethane hydrocarbons per kilowatt-hour of output. The Department anticipates that the commercially available, compression-ignition engines certified to meet the cited non-road engine emission standards will utilize a combination of control technologies including electronically-controlled fuel injection rate systems for fuel injection shaping, multiple fuel injections, and injection timing retard; charge air cooling; and exhaust gas recirculation. This control option would result in total NO_x emissions of less than 2.5 tons per year from all three internal combustion engines, assuming negligible emissions of nonmethane hydrocarbons.

The highest-ranked control option for NO_x emissions involves the use of SCR in conjunction with the second-ranked control option. There are no available data characterizing the NO_x emission levels achievable with this equipment configuration. For the purposes of this BACT analysis, the Department has assumed that 80 percent reduction in NO_x emissions, down to a total annual NO_x emission level of 0.5 tons from all three engines, is achievable with SCR. This likely overstates the achievable NO_x emission reduction with SCR by a significant amount, as each engine will have very little time operating under the steady-state conditions favorable for SCR system performance. Nonetheless, the reasonableness of the Department’s assumption regarding SCR efficiency is not material to the Department’s preliminary BACT determination.

Step 4 - Evaluate More Effective Control Options

In the case of each internal combustion engine, the second-ranked control option will not cause any adverse energy, environmental, or economic impacts. The highest-ranked control option (i.e., the addition of SCR), when considered in comparison with the second-ranked control option, will cause adverse energy and economic impacts, and will yield both beneficial and adverse environmental impacts. The adverse energy impact

is due to the electrical requirements of the SCR system operation and to the reduction in energy efficiency attributable to the pressure drop across the SCR catalyst grid. The adverse energy impacts are relatively minor and were not a significant factor in the BACT decision.

The adverse environmental impacts attributable to the addition of the SCR system include the use of ammonia reagent, with associated storage, shipping and handling risks; the handling and disposal of a spent catalyst as a solid waste stream; ammonia emissions; and, indirectly, formation of PM₁₀ and visible plume from ammonia salt precipitates. The proposed refinery will use aqueous ammonia as the active reagent in its SCR systems, as opposed to the more hazardous anhydrous ammonia, so this is a relatively minor environmental impact and was not a significant factor in the BACT decision. Similarly, extensive industry experience with SCR systems indicates that the removal and disposal of spent SCR catalyst can be conducted safely, with insignificant risk to the environment. To the extent that the safe removal and disposal of spent catalyst results in an economic penalty, that cost is considered in the evaluation of adverse economic impacts discussed below. Otherwise, the environmental impacts of spent catalyst removal and disposal were not a significant factor in the BACT decision.

Ammonia “slip,” or ammonia that is injected in the SCR system and exits the unit without participating in the chemical reduction of NO_x emissions, leads directly to emissions of ammonia and indirectly to the formation of visible plumes, secondary particulate matter, and visibility impairment. These problems are less severe when SCR catalyst is new and activity is highest, because the ammonia injection rate can be set to near-stoichiometric levels. As the catalyst ages, its activity decreases, and a higher ammonia reagent injection rate is required to maintain the rate of the NO_x reduction reaction necessary for continuous compliance with NO_x emission limits. This tends to result in increasing levels of ammonia slip.

The final consideration in the evaluation of alternative NO_x control options is the adverse economic impact associated with the application of SCR for the internal combustion engines. The Department’s evaluation of these adverse economic impacts is based on cost information provided by the Permittee in Table 6.11-1 of its revised permit application. The Department’s evaluation shows that the cost effectiveness of adding SCR systems to the internal combustion engines is more than \$80,000 per ton of NO_x emission reduction, assuming 200 hours of operation per year for each engine. The Department considers these to be significant, adverse economic impacts.

Considering these adverse economic impacts as well as the adverse

environmental impacts and the relatively insignificant air quality benefits that would result, the Department concludes that requiring SCR for the internal combustion engines cannot be justified as BACT. Therefore, the Department considers BACT for NO_x emissions from the internal combustion engines to be the use of engines certified by the engine manufacturer to meet the emission standards for model year 2006 and later non-road, compression-ignition engines, as codified at 40 CFR § 89.112.

Step 5 - Establish BACT

The Department considers BACT for NO_x emissions from the three reciprocating, lean-burn, Diesel-fired, compression-ignition internal combustion engines to be the use of engines certified by the engine manufacturer to meet the emission standards for model year 2006 and later non-road, compression-ignition engines, as codified at 40 CFR § 89.112. Due to the very low emissions from these sources, and due to the availability of engines that are certified to achieve this emission level, the Department has determined that an equipment design standard rather than an emission rate limit is appropriate. Compliance with the equipment design standard will be demonstrated using records of the engine manufacturer's emission performance guarantee.

3. BACT for Carbon Monoxide

Step 1 - Identify All Control Options

Identified control technologies and techniques for CO emissions include combustion modifications and post-combustion control devices (catalytic oxidation or NSCR).

Step 2 - Eliminate Technically Infeasible Control Options

NSCR has not been demonstrated to function efficiently on lean-burn internal combustion engines. Therefore, NSCR is not considered a technically feasible option for controlling CO emissions from the internal combustion engines at the proposed refinery.

Step 3 - Characterize Control Effectiveness of Technically Feasible Control Options

The third-ranked control option for CO emissions comprises the use of internal combustion engines certified by the engine manufacturer to meet the emission standards for model year 2006 and later non-road, compression-ignition engines, as codified at 40 CFR § 89.112. For the emergency generator engine, with a rated power output in excess of 560 kilowatts, the relevant emission standards are known as the "Tier 2"

standards and include a limit of 3.5 grams of CO per kilowatt-hour of output. For the emergency fire water pump engines, each with a rated power output between 130 and 560 kilowatts, the relevant emission standards are known as the “Tier 3” standards and include a limit of 3.5 grams of CO per kilowatt-hour of output. The Department anticipates that the commercially available, compression-ignition engines certified to meet the cited non-road engine emission standards will utilize combustion modifications in order to meet these emission standards. This control option would result in total CO emissions of approximately 1.73 tons per year from all three internal combustion engines.

The second-ranked control option for CO emissions comprises the use of internal combustion engines that are not certified by the engine manufacturer to meet the emission standards for model year 2006 and later non-road, compression-ignition engines. Because these engines do not incorporate the NO_x-reducing control techniques described in Section V.M.2 herein, lower CO emissions are possible. Based on data provided in Table 3.4-1 in U.S. EPA’s AP-42 emission factor compilation, CO emissions of 0.0055 lb/hp-hr are achievable with this control option. This control option would result in total CO emissions of approximately 1.66 tons per year from all three internal combustion engines.

The highest-ranked control option for each internal combustion engine involves the use of catalytic oxidation in conjunction with the second-ranked control option. There are no available data characterizing the CO emission levels achievable with this equipment configuration. For the purposes of this BACT analysis, the Department has assumed that 90 percent reduction in CO emissions, down to a total annual CO emission level of 0.17 tons from all three engines, is achievable with catalytic oxidation. This likely overstates the achievable CO emission reduction with oxidation catalyst by a significant amount, as each engine will have very little time operating under the steady-state conditions favorable for oxidation catalyst system performance. Nonetheless, the reasonableness of the Department’s assumption regarding oxidation catalyst system efficiency is not material to the Department’s preliminary BACT determination.

Step 4 - Evaluate More Effective Control Options

In the case of each internal combustion engine, the third-ranked control option (i.e., combustion controls) will not cause any adverse energy, environmental, or economic impacts. The highest-ranked control option (i.e., the addition of catalytic oxidation), when considered in comparison with the second- or third-ranked control options, will cause adverse energy and economic impacts, and will yield both beneficial and adverse environmental impacts. The adverse energy impact is due to the reduction

in energy efficiency attributable to the pressure drop across the oxidation catalyst grid. The adverse energy impacts are relatively minor and were not a significant factor in the BACT decision.

The adverse environmental impacts attributable to the addition of an oxidation catalyst system are due to the handling and disposal of spent catalyst as a solid waste stream. Extensive industry experience with oxidation catalyst systems indicates that the removal and disposal of spent catalyst can be conducted safely, with insignificant risk to the environment. To the extent that the safe removal and disposal of spent catalyst results in an economic penalty, that cost is considered in the evaluation of adverse economic impacts, discussed below. Otherwise, the environmental impacts of spent catalyst removal and disposal were not a significant factor in the BACT decision.

The final consideration in the evaluation of the highest-ranked CO control option is the adverse economic impact associated with the application of oxidation catalyst for the internal combustion engines. The Department's evaluation of these adverse economic impacts is based on cost information provided by the Permittee in Table 6.11-1 of its revised permit application. The Department's evaluation shows that the cost effectiveness of adding oxidation catalyst systems to the internal combustion engines is more than \$100,000 per ton of CO emission reduction, assuming 200 hours of operation per year for each engine. The Department considers these to be significant, adverse economic impacts.

Considering these adverse economic impacts as well as the adverse environmental impacts and the relatively insignificant air quality benefits that would result, the Department concludes that requiring an oxidation catalyst for the internal combustion engines cannot be justified as BACT.

In the case of each internal combustion engine, the second-ranked control option will not cause any adverse energy or economic impacts. However, when considered in comparison with the third-ranked control option, this option will cause adverse environmental impacts. Based on data provided in Table 3.4-1 in U.S. EPA's AP-42 emission factor compilation, NO_x emissions would increase to 0.013 lb/hp-hr under this control option. This represents an increase of approximately 1.4 tons of NO_x per year, in exchange for a CO emission reduction of only 0.07 tons per year. The Department considers the adverse environmental impacts of this control option to outweigh the beneficial environmental impacts.

Therefore, the Department considers BACT for CO emissions from the internal combustion engines to be the use of engines certified by the engine manufacturer to meet the emission standards for model year 2006 and later non-road, compression-ignition engines, as codified at 40 CFR §

89.112.

Step 5 - Establish BACT

The Department considers BACT for CO emissions from the three reciprocating, lean-burn, Diesel-fired, compression-ignition internal combustion engines to be the use of engines certified by the engine manufacturer to meet the emission standards for model year 2006 and later non-road, compression-ignition engines, as codified at 40 CFR § 89.112. Due to the very low emissions from these sources, and due to the availability of engines that are certified to achieve this emission level, the Department has determined that an equipment design standard rather than an emission rate limit is appropriate. Compliance with the equipment design standard will be demonstrated using records of the engine manufacturer's emission performance guarantee.

N. Emergency Flares

Steps 1 - 5

Flares operate primarily as air pollution control devices, but are nonetheless emission sources subject to BACT analyses. The technically feasible control options for emissions of all pollutants from flares are equipment design specifications and work practices: minimizing exit velocity, ensuring adequate heat value of combusted gases, and minimizing the quantity of gases combusted. Each of these control options is technically feasible and is required in the proposed permit for the emergency flares at the proposed refinery.

The equipment design criteria for the emergency flares in the proposed permit are based largely on the parallel requirements set forth in the NSPS regulations (40 CFR 60.18) and the NESHAP regulations (40 CFR 63.11). These include a maximum allowable exit velocity, a requirement for smokeless operation, and a minimum allowable net heating value for gases combusted in the flares. In addition, the proposed permit includes terms that reflect and make enforceable the Permittee's commitment to operate these flares only to control emissions during periods of upset and malfunction. This latter requirement will have the immediate effect of minimizing the use of the emergency flares and the secondary effect of minimizing total flare emissions. The Department is not aware of any more stringent requirements imposed on flares at any other petroleum refinery, nor any other technically feasible control options for emissions of any pollutants from flares.

O. Miscellaneous Fugitive Dust Sources

Steps 1 - 4

Various activities associated with the construction and operation of the proposed refinery are potential sources of particulate matter (dust) emissions. Numerous work practices are available and technically feasible for minimizing these emissions, as provided by A.A.C. Title 18, Chapter 2, Articles 6 and 7. One control option not addressed by those rules is a requirement that all on-site roadways and vehicle parking lots be paved. The Department considers this to be available and technically feasible.

Step 5 - Establish BACT

The Department has determined that conformance to A.A.C. Title 18, Chapter 2, Articles 6 and 7, plus a requirement for the paving of all on-site roadways and vehicle parking lots, represents BACT for miscellaneous fugitive dust sources. These work practices are included in the proposed permit.

VI. EMISSION LIMITS, TESTING, MONITORING, RECORDKEEPING, AND REPORTING

This section of the Technical Support Document summarizes the requirements that are applicable to each of the emission units at the proposed refinery and describes the rationale of the Department in establishing case-by-case permit terms not discussed elsewhere. These requirements are presented in tabular format in Table VI-A and are in text format in Sections VI.A through VI.CC.

TABLE VI-A. SUMMARY OF PERMIT CONDITIONS

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
Crude Unit					
	Atmospheric Crude Charge Heater				
	Operating Limits	Fired with natural gas and RFG only (PSD)		Not applicable	Recording of fuels combusted
		Maximum heat input 346 MMBtu/hr (PSD)		Not applicable	Monitoring and recording of heat input rate
	SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)		Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
		Maximum sulfur in RFG 35 ppmv (PSD)		Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
	PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)		Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
	NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)		Not applicable	CEMS
		Install, maintain, and operate low-NO _x burners and SCR (PSD)		Not applicable	Not applicable
	CO	Maximum emissions 0.04 lb/MMBtu (PSD)		Not applicable	CEMS

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS	
		Ammonia	Maximum emissions 5.0 ppmvd @ 0% O ₂ (PSD)	Not applicable	CEMS	
	Vacuum Crude Charge Heater					
		Operating Limits		Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
				Maximum heat input 101 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
	SO ₂		Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS	
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur	
	PM ₁₀		Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable	
	NO _x		Maximum emissions 0.034 lb/MMBtu (PSD)	Not applicable	CEMS	
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable	
	CO		Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS
Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Gas Concentration Plant					
Distillation Units					
		VOC	Reduce TOC by 98% or to 20 ppmvd @ 3% O ₂ by routing into flame zone of process heater(s) (NSPS)	Initial test using Method 18 for process heater(s) with heat input capacity less than 150 MMBtu/hr	Monitor and record flow into process heater(s); monitor and record periods of operation for process heater(s) of heat input capacity 150 MMBtu/hr or greater; monitor and record flame zone temperature for process heater(s) of heat input capacity less than 150 MMBtu/hr; maintain records for performance tests including a description of location vent streams introduced into the process heater and average combustion temperature for process heater(s) of heat input capacity less than 150 MMBtu/hr; maintain records of periods when the vent stream is diverted from the process heater(s) or has no flow rate
Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
Hydrocracker Unit					
	Hydrocracker Unit Charge Heater				
	Operating Limits	Fired with natural gas and RFG only (PSD)		Not applicable	Recording of fuels combusted
		Maximum heat input 70 MMBtu/hr (PSD)		Not applicable	Monitoring and recording of heat input rate
	SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)		Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
		Maximum sulfur in RFG 35 ppmv (PSD)		Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
	PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)		Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
	NO _x	Maximum emissions 0.034 lb/MMBtu (PSD)		Not applicable	CEMS
		Install, maintain, and operate low-NO _x burners (PSD)		Not applicable	Not applicable
	CO	Maximum emissions 0.04 lb/MMBtu (PSD)		Not applicable	CEMS
		Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)		Initial and annual tests using Methods 10, 10A, or 10B	Not applicable

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
Hydrocracker Unit Main Fractionator Heater					
	Operating Limits	Fired with natural gas and RFG only (PSD)		Not applicable	Recording of fuels combusted
		Maximum heat input 211 MMBtu/hr (PSD)		Not applicable	Monitoring and recording of heat input rate
	SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)		Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
		Maximum sulfur in RFG 35 ppmv (PSD)		Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
	PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)		Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
	NO _x	Maximum emissions 0.025 lb/MMBtu (PSD)		Not applicable	CEMS
		Install, maintain, and operate low-NO _x burners (PSD)		Not applicable	Not applicable
	CO	Maximum emissions 0.04 lb/MMBtu (PSD)		Not applicable	CEMS
		Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)		Not applicable	CEMS
	Equipment Leaks				

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Naphtha Hydrotreater Unit					
	Naphtha Hydrotreater Charge Heater				
	Operating Limits	Fired with natural gas and RFG only (PSD)		Not applicable	Recording of fuels combusted
		Maximum heat input 21.4 MMBtu/hr (PSD)		Not applicable	Monitoring and recording of heat input rate
	SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)		Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
		Maximum sulfur in RFG 35 ppmv (PSD)		Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
	PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)		Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
	NO _x	Maximum emissions 0.030 lb/MMBtu (PSD)		Not applicable	CEMS
		Install, maintain, and operate low-NO _x burners (PSD)		Not applicable	Not applicable
	CO	Maximum emissions 0.04 lb/MMBtu (PSD)		Not applicable	CEMS

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Initial and annual tests using Methods 10, 10A, or 10B	Not applicable
Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Catalytic Reforming Unit					
Catalytic Reforming Unit Charge Heater					
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
			Maximum heat input 122 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
		NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)	Not applicable	CEMS

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
			Install, maintain, and operate low-NO _x burners and SCR (PSD)	Not applicable	Not applicable	
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS	
		Ammonia	Maximum emissions 5.0 ppmvd @ 0% O ₂ (PSD)	Not applicable	CEMS	
	Catalytic Reforming Unit Interheater No. 1					
		Operating Limits		Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
				Maximum heat input 192 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
		SO ₂		Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
				Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
		PM ₁₀		Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
		NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)	Not applicable	CEMS	
			Install, maintain, and operate low-NO _x burners and SCR (PSD)	Not applicable	Not applicable	
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS	
		Ammonia	Maximum emissions 5.0 ppmvd @ 0% O ₂ (PSD)	Not applicable	CEMS	
	Catalytic Reforming Unit Interheater No. 2					
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted	
			Maximum heat input 129 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate	
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS	
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable	
		NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)	Not applicable	CEMS	
			Install, maintain, and operate low-NO _x burners and SCR (PSD)	Not applicable	Not applicable	
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS	
		Ammonia	Maximum emissions 5.0 ppmvd @ 0% O ₂ (PSD)	Not applicable	CEMS	
	Catalytic Reforming Unit Debutanizer Reboiler					
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted	
			Maximum heat input 23.2 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate	
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping		
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur		
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable		
		NO _x	Maximum emissions 0.030 lb/MMBtu (PSD)	Not applicable	CEMS		
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable		
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS		
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Initial and annual tests using Methods 10, 10A, or 10B	Not applicable		
		Catalytic Reforming Unit Catalyst Regenerator					
			Equipment Design / Work Practice	At all times, operate in a manner consistent with good air pollution control practices for minimizing emissions (NESHAP)	Not applicable	Startup, shutdown, and malfunction plan	
			NO _x	Maximum emissions 0.82 lb/hr (PSD)	Initial and annual tests using Methods 7 or 7E	Not applicable	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		CO	Maximum emissions 0.50 lb/hr (PSD)	Initial and annual tests using Methods 10 or 10B	Not applicable
		Organic HAP	If reactor vent pressure exceeds 5 psig, reduce TOC to 20 ppmvd @ 3% O ₂ (NESHAP)	Initial test using Method 25A	Operation, maintenance and monitoring plan
			Maintain daily average ratio of perchloroethylene feed rate to catalyst circulation rate at or below the maximum ratio established during performance testing	Not applicable	Monitor and record hourly and daily average perchloroethylene feed rate and catalyst circulation rate; determine and record daily average ratio of perchloroethylene feed rate to catalyst circulation rate
		Inorganic HAP	Reduce HCl by 97% or to 10 ppmvd @ 3% O ₂ using a caustic scrubber (NESHAP)	Initial test using Method 26A	Operation, maintenance and monitoring plan
			Maintain daily average pH of scrubbing liquid above the minimum level established during performance testing	Not applicable	Monitor and record daily average scrubbing liquid pH
			Maintain daily average scrubber liquid-to-gas ratio above the minimum ratio established during performance testing	Not applicable	Monitor and record scrubbing liquid flow rate and exhaust gas flow rate; determine and record hourly and daily average liquid-to-gas ratio

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Visible Emissions	Maximum opacity 20% (State Rule)	Not applicable	Not applicable
	Equipment Leaks				
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Isomerization Unit					
	Equipment Leaks				
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Distillate Hydrotreater Unit					
	Distillate Hydrotreater Charge Heater				
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
			Maximum heat input 25 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
Maximum sulfur in RFG 35 ppmv (PSD)			Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable	
		NO _x	Maximum emissions 0.033 lb/MMBtu (PSD)	Not applicable	CEMS	
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable	
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Initial and annual tests using Methods 10, 10A, or 10B	Not applicable	
	Distillate Hydrotreater Splitter Reboiler					
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted	
			Maximum heat input 117 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate	
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS	
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable	
		NO _x	Maximum emissions 0.032 lb/MMBtu (PSD)	Not applicable	CEMS	
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable	
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS	
	Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs	
Butane Conversion Unit						
	Butane Conversion Unit Dehydrogenation Reactor Charge Heater					
	Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted		
		Maximum heat input 311 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate		

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping		
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS		
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur		
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable		
		NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)	Not applicable	CEMS		
			Install, maintain, and operate low-NO _x burners and SCR (PSD)	Not applicable	Not applicable		
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS		
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS		
		Ammonia	Maximum emissions 5.0 ppmvd @ 0% O ₂ (PSD)	Not applicable	CEMS		
		Butane Conversion Unit Dehydrogenation Reactor Interheater					
			Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Maximum heat input 328 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
		NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)	Not applicable	CEMS
			Install, maintain, and operate low-NO _x burners and SCR (PSD)	Not applicable	Not applicable
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS
		Ammonia	Maximum emissions 5.0 ppmvd @ 0% O ₂ (PSD)	Not applicable	CEMS
		Butane Conversion Unit Isostripper Reboiler			

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping		
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted		
			Maximum heat input 222 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate		
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS		
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur		
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable		
		NO _x	Maximum emissions 0.030 lb/MMBtu (PSD)	Not applicable	CEMS		
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable		
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS		
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS		
		Butane Conversion Unit Catalyst Regenerator					
			Visible Emissions	Maximum opacity 20% (State Rule)	Not applicable	Not applicable	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		NO _x	Maximum emissions 0.82 lb/hr (PSD)	Initial and annual tests using Methods 7 or 7E	Not applicable
		CO	Maximum emissions 0.50 lb/hr (PSD)	Initial and annual tests using Methods 10 or 10B	Not applicable
	Butane Conversion Unit Distillation Units				
		VOC	Reduce TOC by 98% or to 20 ppmvd @ 3% O ₂ by routing into flame zone of process heater(s) (NSPS)	Initial test using Method 18 for process heater(s) with heat input capacity less than 150 MMBtu/hr	Monitor and record flow into process heater(s); monitor and record periods of operation for process heater(s) of heat input capacity 150 MMBtu/hr or greater; monitor and record flame zone temperature for process heater(s) of heat input capacity less than 150 MMBtu/hr; maintain records for performance tests including a description of location vent streams introduced into the process heater and average combustion temperature for process heater(s) of heat input capacity less than 150 MMBtu/hr; maintain records of periods when the vent stream is diverted from the process heater(s) or has no flow rate
	Reactor Processes				
		VOC	Reduce TOC by 98% or to 20 ppmvd @ 3% O ₂ by routing into flame zone of process heater(s) (NSPS)	Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from process heater flame zone(s)
	Equipment Leaks				

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Benzene Reduction Unit					
	Equipment Leaks				
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Delayed Coking Unit					
	Delayed Coking Unit Charge Heater No. 1				
	Operating Limits	Fired with natural gas and RFG only (PSD)		Not applicable	Recording of fuels combusted
		Maximum heat input 99.5 MMBtu/hr (PSD)		Not applicable	Monitoring and recording of heat input rate
	SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)		Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
		Maximum sulfur in RFG 35 ppmv (PSD)		Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
	PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)		Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
		NO _x	Maximum emissions 0.030 lb/MMBtu (PSD)	Not applicable	CEMS	
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable	
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Initial and annual tests using Methods 10, 10A, or 10B	Not applicable	
	Delayed Coking Unit Charge Heater No. 2					
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted	
			Maximum heat input 99.5 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate	
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS	
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur	
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable	
		NO _x	Maximum emissions 0.030 lb/MMBtu (PSD)	Not applicable	CEMS	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Initial and annual tests using Methods 10, 10A, or 10B	Not applicable
	Equipment Leaks				
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Petroleum Coke Storage, Handling, and Loading					
	Coke Pit and Coke Pad				
		Equipment Design / Work Practice	Maximum combined surface area of 48,000 square feet (PSD)	Not applicable	Not applicable
			Completely walled enclosure, with all coke storage and handling operations conducted at least five feet below the lowest point on the top of the walled enclosure (PSD)	Not applicable	Once per shift, determine and record height of coke storage piles

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
			Minimum coke moisture content of 12% by weight throughout the Coke Pit and Coke Pad (PSD)	Not applicable	Once per day, collect and analyze a coke sample from the Coke Pad; determine and record coke moisture content	
		Visible Emissions	No visible emissions across the refinery's property boundary (PSD)	Not applicable	Once per shift, conduct visible emissions observations using Method 22	
	Coke Crusher					
		Equipment Design / Work Practice		Located within the Coke Pad enclosure (PSD)	Not applicable	Not applicable
				Partial enclosure surrounding all sides and top (PSD)	Not applicable	Not applicable
				Minimum coke moisture content of 12% by weight (PSD)	Not applicable	Once per day, collect and analyze a coke sample from the transfer point between the Coke Crusher and the Coke Conveyor; determine and record coke moisture content
		Visible Emissions	No visible emissions (PSD)	Not applicable	Once per shift, conduct visible emissions observations using Method 22	
	Coke Conveyor					
		Equipment Design / Work Practice	Conveying only from Coke Crusher to Coke Silo (PSD)	Not applicable	Not applicable	

Work Practice

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
			Full enclosure of Coke Conveyor and transfer points (PSD)	Not applicable	Not applicable	
			Minimum coke moisture content of 12% by weight (PSD)	Not applicable	Once per day, collect and analyze a coke sample from the transfer point between the Coke Crusher and the Coke Conveyor; determine and record coke moisture content	
		Visible Emissions	No visible emissions (PSD)	Not applicable	Once per shift, conduct visible emissions observations using Method 22	
	Coke Silo					
		Equipment Design / Work Practice	Fully enclosed, with all emissions vented through a baghouse (PSD)	Not applicable	Operation and maintenance plan	
		PM	Maximum emissions 0.005 gr/dscf (PSD, State Rule)	Initial and annual tests using Method 5	Operation and maintenance plan	
		Visible Emissions	No visible emissions (PSD)	Not applicable	Once per shift, conduct visible emissions observations using Method 22	
	Coke Rail Car Loading					
		Equipment Design / Work Practice	Full enclosure, with overlapping flaps or sliding doors on the rail car entrance and exit (PSD)	Not applicable	Not applicable	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Coke transfer using a telescoping chute, with a maximum coke drop distance of four feet (PSD)	Not applicable	Not applicable
			Minimum coke moisture content of 12% by weight (PSD)	Not applicable	Once per day, collect and analyze a coke sample from the Coke Rail Car Loading Chute; determine and record coke moisture content
		Visible Emissions	No visible emissions (PSD)	Not applicable	Once per shift, conduct visible emissions observations using Method 22
Amine Regeneration Unit					
	Amine Regenerator				
		Operating Limits	All gases containing H ₂ S or VOC routed to Sulfur Recovery Plant (PSD)	Not applicable	Not applicable
			Maximum of 210,000 gallons rich amine solution processed per day (PSD)	Not applicable	Once per day, determine and record the quantity of rich amine solution processed
			Rich amine solution re-routed to the Rich Amine Tank and acid gas flaring ceased within fifteen minutes after the start of the acid gas flaring or other upset that results in excess emissions (PSD)	Not applicable	Not applicable (recordkeeping requirements are in effect for emission points at which excess SO ₂ emissions may occur)

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
Rich Amine Tank					
	Operating Limits	Minimum available rich amine solution storage capacity 210,000 gallons (PSD)		Not applicable	Maintain records of tank dimensions and capacity; once per day, determine and record quantity of liquid being stored
		True vapor pressure of stored liquids less than 3.4 kPa (NESHAP)		Not applicable	Maintain records of true vapor pressure of stored liquids
Lean Amine Tank					
	Operating Limits	Minimum available lean amine solution 210,000 gallons (PSD)		Not applicable	Maintain records of tank dimensions and capacity; once per day, determine and record available lean amine solution
		True vapor pressure of stored liquids less than 3.4 kPa (NESHAP)		Not applicable	Maintain records of true vapor pressure of stored liquids
Rich Amine Three Phase Separator					
	Operating Limit	Vent stream routed to Sulfur Recovery Plant Thermal Oxidizer (PSD, NESHAP)		Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from the Sulfur Recovery Plant Thermal Oxidizer, including the time and duration of such bypass or diversion; alternatively, secure the bypass line valve in the closed position, and conduct and record monthly visual inspections of the valve closure mechanism
Equipment Leaks					

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Sour Water Stripper					
Sour Water Flash Drum					
	Operating Limit	Vent stream routed to Sulfur Recovery Plant Thermal Oxidizer (PSD, NESHAP)	Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from the Sulfur Recovery Plant Thermal Oxidizer, including the time and duration of such bypass or diversion; alternatively, secure the bypass line valve in the closed position, and conduct and record monthly visual inspections of the valve closure mechanism	
Sour Water Stripper					
	Operating Limits	All gases containing H ₂ S or VOC routed to Sulfur Recovery Plant (PSD)	Not applicable	Not applicable	
		Maximum of 3.78 million gallons sour water processed per day (PSD)	Not applicable	Once per day, determine and record the quantity of sour water processed	
		Sour water re-routed to the Sour Water Tank and acid gas flaring ceased within fifteen minutes after the start of the acid gas flaring or other upset that results in excess emissions (PSD)	Not applicable	Not applicable (recordkeeping requirements are in effect for emission points at which excess SO ₂ emissions may occur)	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
Sour Water Tank					
		Operating Limits	Minimum available sour water storage capacity 3.78 million gallons (PSD)	Not applicable	Maintain records of tank dimensions and capacity; once per day, determine and record quantity of liquid being stored and available storage capacity
			True vapor pressure of stored liquids less than 76.6 kPa (NSPS)	Not applicable	Maintain records of true vapor pressure of stored liquids
		Equipment Design	Equipped with fixed roof and internal floating roof with dual seals	Conduct inspection of internal floating roof and seals before initial fill, each time the tank is emptied and degassed, and at least annually	Not applicable
		Operating Limits	Vent stream routed to a dedicated dual carbon canister system (PSD)	Not applicable	Daily monitoring of exhaust stream to detect breakthrough.
Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Sulfur Recovery Plant					
	Sulfur Recovery Units				

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
		Equipment Design / Work Practice	At all times, operate in a manner consistent with good air pollution control practices for minimizing emissions (NESHAP)	Not applicable	Startup, shutdown, and malfunction plan	
		Operating Limits	Vent stream routed to inlet of Tail Gas Treatment Unit (PSD)	Not applicable	Operation, maintenance and monitoring plan	
			Vent stream from Tail Gas Treatment Unit routed to inlet of Sulfur Recovery Plant Thermal Oxidizer (PSD)	Not applicable	Operation, maintenance and monitoring plan	
	Sulfur Recovery Plant Thermal Oxidizer					
		Operating Limits	Not applicable	Not applicable	Monitoring and recording of heat input rate	
		SO ₂	Maximum exhaust concentration 250 ppmvd @ 0% O ₂ (NSPS, NESHAP)	Initial test using Method 6 or 6C	CEMS	
			Maximum emissions 33.5 lb/hr (PSD)	Not applicable	CEMS	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		VOC	Reduce emissions of VOC in vent streams from Sour Water Flash Drum and Rich Amine Three Phase Separator by 98% or to 20 ppmvd @ 3% O ₂ , whichever is less stringent (NESHAP, PSD)	Initial test using Method 18	Not applicable
			Maintain exhaust gas volumetric flow rate at or below the level that corresponds to a minimum residence time of 0.75 seconds (NESHAP, PSD)	Not applicable	Monitoring and recording of exhaust gas volumetric flow rate
			Maintain combustion chamber temperature at least as high as the level established during the performance test (NESHAP, PSD)	Not applicable	Monitoring and recording of combustion chamber temperature
		Reduced Sulfur Compounds	Maximum emissions 0.089 lb/hr (PSD)	Initial test using Method 15	Not applicable

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
			Maintain combustion chamber temperature at least as high as the level established during the performance test	Not applicable	Monitoring and recording of combustion chamber temperature	
		NO _x	Maximum emissions 0.06 lb/MMBtu (PSD)	Not applicable	CEMS	
			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable	
	Sulfur Pits					
		Operating Limit	Vent stream routed to inlet of a Sulfur Recovery Unit (PSD)	Not applicable	Operation, maintenance and monitoring plan	
	MDEA Storage Tank					
		Operating Limits	True vapor pressure of stored liquids less than 3.4 kPa (PSD)	Not applicable	Maintain records of true vapor pressure of stored liquids	
		Equipment Design / Work Practice	Not applicable	Not applicable	Maintain records of storage tank dimensions and capacity	
	Sulfur Product Loading Racks					

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Operating Limit	Maximum of 15 ppmw H ₂ S in sulfur being loaded into trucks or rail cars (PSD)	Not applicable	Once per day, analyze and record H ₂ S in sulfur stored in Sulfur Pit No. 1 and Sulfur Pit No. 2
	Equipment Leaks				
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Hydrogen Plant					
	Hydrogen Reformer Heater				
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
			Maximum heat input 1,435 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
		NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)	Not applicable	CEMS

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Install, maintain, and operate low-NO _x burners and SCR (PSD)	Not applicable	Not applicable
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS
		Ammonia	Maximum emissions 5.0 ppmvd @ 0% O ₂ (PSD)	Not applicable	CEMS
Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Group "A" Storage Tanks					
Storage Vessels					
		Equipment Design / Work Practice	Emissions routed to RFG system via a vapor compression system (PSD, NESHAP)	Not applicable	Monitor and record any emissions bypassed or diverted from the vapor compression system or RFG system, including the duration of the bypass and the reason why bypass was necessary

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Degassing and cleaning emissions controlled by liquid balancing, incineration, condensation, or other approved measure (PSD)	Not applicable	Maintain records of degassing equipment operation, including tank capacity; material stored; flow rate and VOC concentration of gases vented to degassing equipment; total amount of VOC processed in degassing equipment; control efficiency of degassing equipment; and degassing equipment operating parameters
Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Group "B" Storage Tanks					
Storage Vessels					
		Equipment Design / Work Practice	Vent stream routed to Tank Farm Thermal Oxidizer (PSD, NESHAP)	Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from Tank Farm Thermal Oxidizer, including periods of planned routine maintenance performed on the control device
			Equipped with fixed roof and internal floating roof with a dual seal closure device (PSD)	Not applicable	Perform inspections and maintain records of inspection results

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Degassing and cleaning emissions controlled by liquid balancing, incineration, condensation, or other approved measure (PSD)	Not applicable	Maintain records of degassing equipment operation, including tank capacity; material stored; flow rate and VOC concentration of gases vented to degassing equipment; total amount of VOC processed in degassing equipment; control efficiency of degassing equipment; and degassing equipment operating parameters
Tank Farm Thermal Oxidizer					
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
			Not applicable (State Rule)	Not applicable	Monitoring and recording of heat input rate
			Periods of downtime, due to planned routine maintenance, limited to 240 hours per year (NESHAP, PSD)	Not applicable	Maintain records of downtime due to planned routine maintenance, including the time and date of the beginning and end of each maintenance event
		VOC, Organic HAP	Reduce inlet emissions of total organic HAP by 95% or greater (NESHAP)	Not applicable	Prepare and maintain records of design evaluation; monitor and record combustion chamber temperature
			Minimum design destruction efficiency of 99.9% (PSD)	Not applicable	Prepare and maintain records of engineering design analysis
			Maximum flow rate corresponding to a minimum combustion chamber residence time of 0.75 seconds (PSD)	Not applicable	Monitor and record exhaust gas volumetric flow rate; prepare and maintain records of engineering design analysis

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Maintain minimum combustion chamber temperature of 1,600 °F, five-minute average (PSD)	Not applicable	Prepare and maintain records of design evaluation; monitor and record combustion chamber temperature; perform annual inspections of the Tank Farm Thermal Oxidizer burner and combustion chamber temperature monitoring system
		PM ₁₀	Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
		NO _x	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
			Maximum sulfur in auxiliary fuel 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
		Equipment Leaks			
	VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs	
Group "D" Storage Tanks					
	Storage Vessels				

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Operating Limit	Maintain minimum 204.9 kPa operating pressure (PSD, NESHAP)	Not applicable	Maintain records of operating pressure
Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Group "E" Storage Tank					
Storage Vessel					
		Equipment Design / Work Practice	Exhaust gases cooled to a temperature of 120 °F or less and routed through a filter for particulate matter removal (PSD)	Not applicable	Monitor and record tank exhaust gas temperature at least once per week
			Not applicable	Not applicable	Maintain records of storage tank dimensions and capacity
		Visible Emissions	No visible emissions, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing (NSPS)	Initial test using Method 9	Conduct and maintain records of daily visible emissions observations using Method 9

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Operational Limit	Maintain true vapor pressure of stored liquids less than 3.5 kPa (NSPS)	Not applicable	Maintain records of the maximum true vapor pressure of stored liquids, types of liquids, and period of storage
Truck and Rail Car Loading Racks					
Gasoline Product Truck and Rail Car Loading Racks					
		Equipment Design / Work Practice	Equipped with vapor collection and processing system (NESHAP)	Not applicable	Not applicable
			Loading only into cargo tanks using vapor collection equipment that is compatible with the loading rack vapor collection system (NESHAP)	Not applicable	Maintain records of cargo tanks loaded
			Loading only into vapor-tight cargo tanks (NESHAP)	Not applicable	Maintain records of cargo tanks loaded; obtain and maintain documentation of vapor tightness for each cargo tank loaded
			Maximum 460 mm H ₂ O gauge pressure in cargo tank during loading (PSD, NESHAP)	Initial test, using pressure measurement device	Continuous monitoring of system pressure
			Gases displaced from cargo tanks routed to regenerative adsorption system (PSD, NESHAP)	Not applicable	Not applicable

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
			Maintain regenerative adsorption system exhaust VOC concentration less than the concentration level established during the VOC performance test (PSD, NESHAP)	Not applicable	CEMS	
			Exhaust from regenerative adsorption systems routed to thermal oxidizer (PSD)	Not applicable	Not applicable	
		VOC	Maximum VOC in regenerative adsorption system exhaust 7.5 mg per liter of gasoline loaded (PSD, NESHAP)	Initial test using Methods 25A or 25B	Maintain records of test results	
	Distillate Product Truck and Rail Car Loading Racks					
		Equipment Design / Work Practice		Equipped with vapor collection system (PSD)	Not applicable	Not applicable
				Loading only into cargo tanks using vapor collection equipment that is compatible with the loading rack vapor collection system (PSD)	Not applicable	Maintain records of cargo tanks loaded
				Maximum 460 mm H ₂ O gauge pressure in cargo tank during loading (PSD)	Not applicable	Continuous monitoring of system pressure

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Gases displaced from cargo tanks routed to thermal oxidizer (PSD)	Not applicable	Not applicable
Truck and Rail Car Loading Rack Thermal Oxidizers					
		Operational Limits	Fired only with natural gas and RFG as auxiliary fuels (PSD)	Not applicable	Recording of fuels combusted
		Equipment Design / Work Practice	Maintain combustion chamber temperature at a level at least as high as the temperature established during the VOC performance test (PSD)	Not applicable	Continuously monitor and record combustion chamber temperature; perform annual inspections of the Thermal Oxidizer burners and combustion chamber temperature monitoring systems
			Maintain exhaust gas volumetric flow rate at or below the level that corresponds to a minimum residence time of 0.75 seconds (NESHAP, PSD)	Not applicable	Monitoring and recording of exhaust gas volumetric flow rate

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		VOC	Maximum emissions 1.25 lb per million gallons loaded at the gasoline product loading racks plus 22.0 lb per million gallons loaded at the distillate product loading racks (PSD)	Initial test using Methods 25A or 25B	Maintain records of test results
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS
			Maximum sulfur in auxiliary fuel 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur
	Equipment Leaks				
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring and repairs
Wastewater Treatment Plant					
	Wastewater Collection System (Drains)				
		Equipment Design/Work Practice	Equipped with leak-free covers on all openings (PSD, NESHAP)	Not applicable	Perform inspections; maintain records of inspections

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Either the junction box is equipped with water seal controls or a plug, or the vent stream is routed to either the Wastewater Treatment Plant Thermal Oxidizer or a dedicated dual carbon canister system (PSD, NESHAP)	Not applicable	If using water seal controls or a plug, perform inspections and maintain records of inspection results; if using thermal oxidizer, monitor and record any vent stream flow that is bypassed or diverted from thermal oxidizer; if using dedicated dual carbon canister system, continuously monitor exhaust stream for breakthrough
Equalization Tank					
		Equipment Design / Work Practice	Equipped with a fixed roof and leak-free covers on all openings (PSD, NESHAP)	Not applicable	Perform inspections; maintain records of inspections
			Equipped with a closed-vent system, with the vent stream routed to Wastewater Treatment Plant Thermal Oxidizer (PSD, NESHAP)	Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from thermal oxidizer
Oil-Water Separator (API Separator)					
		Equipment Design/Work Practice	Equipped with a fixed roof and leak-free covers on all openings (PSD, NESHAP)	Not applicable	Perform inspections; maintain records of inspections

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Equipped with a closed-vent system, with the vent stream routed to Wastewater Treatment Plant Thermal Oxidizer (PSD, NESHAP)	Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from thermal oxidizer
	Dissolved Air Flotation Unit				
		Equipment Design / Work Practice	Equipped with a fixed roof and leak-free covers on all openings (PSD, NESHAP)	Not applicable	Perform inspections; maintain records of inspections
			Equipped with a closed-vent system, with the vent stream routed to Wastewater Treatment Plant Thermal Oxidizer (PSD, NESHAP)	Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from thermal oxidizer
	Biotreater				
		Equipment Design / Work Practice	Equipped with a fixed roof and leak-free covers on all openings (PSD, NESHAP)	Not applicable	Perform inspections; maintain records of inspections
			Equipped with a closed-vent system, with the vent stream routed to Wastewater Treatment Plant Thermal Oxidizer (PSD, NESHAP)	Not applicable	Monitor and record any vent stream flow that is bypassed or diverted from thermal oxidizer
	Containers				

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Equipment Design / Work Practice	Equipped with leak-free covers on all openings (PSD, NESHAP)	Not applicable	Perform inspections; maintain records of inspections
			Equipped with a submerged fill pipe (PSD, NESHAP)	Not applicable	Not applicable
	Waste Treatment Processes, Collectively				
		Benzene	Remove benzene from waste by 99%, mass basis, or to a concentration less than 10 ppmw (NESHAP, PSD)	Not applicable	Perform engineering calculations or measure benzene quantity in waste before and after treatment processes; maintain records of results
			Waste shall not be placed in a surface impoundment (PSD)	Not applicable	Not applicable
	Wastewater Treatment Plant Thermal Oxidizer				
		Operating Limits	Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
			Minimum design destruction efficiency of 99.9% (PSD)	Not applicable	Prepare and maintain records of engineering design analysis
			Maximum flow rate corresponding to a minimum combustion chamber residence time of 0.75 seconds (PSD)	Not applicable	Monitor and record exhaust gas volumetric flow rate; prepare and maintain records of engineering design analysis

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
			Maintain minimum combustion chamber temperature of 1,600 °F, five-minute average (PSD)	Not applicable	Monitor and record combustion chamber temperature; perform annual inspections of the Thermal Oxidizer burner and combustion chamber temperature monitoring system; prepare and maintain records of engineering design analysis	
		SO ₂	Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	SO ₂ CEMS or fuel H ₂ S CEMS	
			Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	SO ₂ CEMS, or fuel sulfur CEMS, or fuel H ₂ S CEMS plus grab sampling & analysis to determine ratio of H ₂ S to total sulfur	
	Wastewater Treatment Plant Spray Dryer Heater					
		Operating Limits		Fired with natural gas and RFG only (PSD)	Not applicable	Recording of fuels combusted
				Maximum heat input 44 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
		SO ₂		Maximum H ₂ S in RFG 0.10 gr/dscf (NSPS)	Initial test using Method 6, 6C, 11, 15, 15A, or 16	CEMS
				Maximum sulfur in RFG 35 ppmv (PSD)	Not applicable	CEMS
		PM ₁₀		Maximum emissions 0.0075 lb/MMBtu (PSD)	Initial and annual tests using Methods 201 or 201A and Method 202	Not applicable
		NO _x		Maximum emissions 0.030 lb/MMBtu (PSD)	Not applicable	CEMS

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping	
Emergency Flares			Install, maintain, and operate low-NO _x burners (PSD)	Not applicable	Not applicable	
		CO	Maximum emissions 0.04 lb/MMBtu (PSD)	Not applicable	CEMS	
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Initial and annual tests using Methods 10, 10A, or 10B	Not applicable	
	Wastewater Treatment Plant Spray Dryer Baghouse					
		Operating Limits	Maintain pressure drop within the range established in the CAM plan	Not applicable	Continuously monitor and record pressure drop	
		Visible Emissions	Maximum opacity 5% (PSD, State Rule)	Not applicable	Perform monthly visible emissions observations using Method 9; maintain records of results	
		PM	Maximum emissions 0.005 gr/dscf (PSD, State Rule)	Initial and annual tests using Method 5	Monitor and record pressure drop and other operating parameters identified in an approved CAM plan; perform monthly inspection of baghouse and baghouse pressure drop monitoring system in accordance with the manufacturer's recommended procedures	
	Equipment Leaks					
		VOC, Organic HAP, H ₂ S	Leak detection and repair program (PSD, NESHAP)	Not applicable	Monitoring for leaks; recording of monitoring results	

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
Emergency Flares					
		Operating Limits	Except during malfunctions, flares shall combust only pipeline-quality natural gas (PSD)	Not applicable	Continuously monitor and record the flow of pilot gas, purge gas, and other gases to each flare; for each flare event when gases other than pipeline-quality natural gas are combusted, identify and record the date and time of the flare event, submit notification to the Director, obtain a sample of the gases being combusted, and analyze the sample for heating value and sulfur content
		Equipment Design / Work Practice	Operated with pilot flame continuously present (PSD)	Not applicable	Continuously monitor and record presence of flame
			Designed and operated with steam assist (PSD)	Not applicable	Maintain record of flare system operation, maintenance, and monitoring plan
			Designed and operated with no visible emissions (PSD)	Not applicable	Perform visible emissions observation using Method 22 during each flare event; maintain records of observations
			Maximum exit velocity 60 ft/sec (PSD)	Not applicable	Maintain record of flare system operation, maintenance, and monitoring plan
			Natural gas purge employed so that the net heating value of gas being combusted is 300 Btu/scf or greater (PSD)	Not applicable	Maintain record of flare system operation, maintenance, and monitoring plan
Steam Boilers					
	Steam Boilers				

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Operating Limits	Fired with natural gas only (PSD)	Not applicable	Recording of fuels combusted
			Maximum heat input 419 MMBtu/hr (PSD)	Not applicable	Monitoring and recording of heat input rate
		NO _x	Maximum emissions 0.0125 lb/MMBtu (PSD)	Not applicable	CEMS
			Maximum emissions 0.20 lb/MMBtu at all times, including periods of startup, shutdown, and malfunction (NSPS)	Initial test using CEMS	CEMS
			Install, maintain, and operate low-NO _x burners and flue gas recirculation (PSD)	Not applicable	Not applicable
		CO	Maximum emissions 0.016 lb/MMBtu (PSD)	Not applicable	CEMS
			Maximum emissions 400 ppmvd @ 3% O ₂ (NESHAP)	Not applicable	CEMS
		Cooling Tower			
	Cooling Tower				

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Equipment Design / Work Practice	Equipped with high-efficiency drift eliminators guaranteed by the manufacturer for a maximum total liquid drift of 0.0005% (PSD)	Not applicable	Maintain records of vendor-guaranteed maximum total liquid drift
		Operating Limits	Maximum cooling water flow rate 80,000 gallons per minute (PSD)	Not applicable	Maintain records of cooling water pumping capacity
		Visible Emissions	Maximum opacity 20% (State Rule)	Not applicable	Not applicable
		PM	Maximum emissions 1.6 lb/hr (PSD, State Rule)	Initial test using either a modified EPA Reference Method 306 or the heated bead test method	Maintain records of cooling water pumping capacity; maintain records of drift rate; perform monthly measurement of total dissolved solids and record results; perform monthly calculation of PM emissions and record results
Heat Exchange System					
		VOC	Leak detection and repair program (PSD)	Not applicable	Monitoring for leaks; recording of monitoring results
Internal Combustion Engines					
Emergency Generator					
		Operating Limits	Fired only with No. 2 Diesel fuel with a maximum sulfur content of 15 ppmw (PSD)	Not applicable	Maintain records of type of fuel combusted; maintain records of sulfur content and method of determination

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Maximum fuel usage 15,600 gallons per year, excluding operation during emergencies (PSD)	Not applicable	Maintain records of quantity of fuel combusted
			Maximum operation 50 hours per year, excluding operation during emergencies and during routine testing and maintenance	Not applicable	Maintain records of quantity of fuel combusted
			Routine operation prohibited during periods when visible emissions observation cannot be performed using Method 9, unless daily visible emissions observation has already been performed (PSD)	Not applicable	Maintain daily records of type and quantity of fuel combusted; maintain records of visible emissions observations
		Visible Emissions	Maximum opacity 40% (State Rule)	Not applicable	Daily visible emissions observations using Method 9 during non-emergency operations; maintain records of visible emissions observations
		Equipment Design / Work Practice	Maximum manufacturer-guaranteed NO _x plus nonmethane hydrocarbon emissions 6.4 grams per kilowatt-hour output (PSD)	Not applicable	Maintain records of manufacturer's emission performance guarantee; maintain records of manufacturer's instructions and recommendations relating to operation and maintenance; maintain records of all maintenance performed on the internal combustion engine

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Maximum manufacturer-guaranteed CO emissions 3.5 grams per kilowatt-hour output (PSD)	Not applicable	Maintain records of manufacturer's emission performance guarantee; maintain records of manufacturer's instructions and recommendations relating to operation and maintenance; maintain records of all maintenance performed on the internal combustion engine
			Maximum manufacturer-guaranteed PM emissions 0.2 grams per kilowatt-hour output (PSD)	Not applicable	Maintain records of manufacturer's emission performance guarantee; maintain records of manufacturer's instructions and recommendations relating to operation and maintenance; maintain records of all maintenance performed on the internal combustion engine
	Fire Water Pump Nos. 1 and 2				
		Operating Limits	Fired only with No. 2 Diesel fuel with a maximum sulfur content of 15 ppmw (PSD)	Not applicable	Maintain records of type of fuel combusted; maintain records of sulfur content and method of determination
			Maximum fuel usage in each engine 7,800 gallons per year, excluding operation during emergencies (PSD)	Not applicable	Maintain records of quantity of fuel combusted
			Maximum operation 50 hours per year, excluding operation during emergencies and during routine testing and maintenance	Not applicable	Maintain records of quantity of fuel combusted

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Routine operation prohibited during periods when visible emissions observation cannot be performed using Method 9, unless daily visible emissions observation has already been performed (PSD)	Not applicable	Maintain daily records of type and quantity of fuel combusted; maintain records of visible emissions observations
		Visible Emissions	Maximum opacity 20% (State Rule)	Not applicable	Daily visible emissions observations using Method 9 during non-emergency operations; maintain records of visible emissions observations
		Equipment Design / Work Practice	Maximum manufacturer-guaranteed NO _x plus nonmethane hydrocarbon emissions 4.0 grams per kilowatt-hour output (PSD)	Not applicable	Maintain records of manufacturer's emission performance guarantee; maintain records of manufacturer's instructions and recommendations relating to operation and maintenance; maintain records of all maintenance performed on the internal combustion engine
			Maximum manufacturer-guaranteed CO emissions 3.5 grams per kilowatt-hour output (PSD)	Not applicable	Maintain records of manufacturer's emission performance guarantee; maintain records of manufacturer's instructions and recommendations relating to operation and maintenance; maintain records of all maintenance performed on the internal combustion engine

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
			Maximum manufacturer-guaranteed PM emissions 0.2 grams per kilowatt-hour output (PSD)	Not applicable	Maintain records of manufacturer's emission performance guarantee; maintain records of manufacturer's instructions and recommendations relating to operation and maintenance; maintain records of all maintenance performed on the internal combustion engine
Fugitive Dust and Miscellaneous Other Sources					
Open Areas, Dry Washes, and Riverbeds					
	Operating Limits	Implement reasonable dust control measures (State Rule)	Not applicable	Maintain records of approved fugitive dust control plan	
Roadways, Streets, and Parking Lots					
	Operating Limits	Implement reasonable dust control measures (State Rule)	Not applicable	Maintain records of approved fugitive dust control plan	
		Pave all roadways, streets, and parking lots (BACT)	Not applicable	Not applicable	
Material Handling and Storage Piles					
	Operating Limits	Implement reasonable dust control measures (State Rules)	Not applicable	Maintain records of approved fugitive dust control plan	
Storage Piles					

Process Unit	Emission Unit	Pollutant/Parameter	Condition (Authority)	Testing	Monitoring/Recordkeeping
		Operating Limits	Implement reasonable dust control measures (State Rule)	Not applicable	Maintain records of approved fugitive dust control plan
	Roadway/Site Cleaning Machinery				
		Operating Limits	Implement reasonable dust control measures (State Rule)	Not applicable	Not applicable
		Visible Emissions	Maximum opacity 40% (State Rule)	Not applicable	Not applicable
	Off-Road Machinery and Other Mobile Sources				
		Visible Emissions	Maximum opacity 40% (State Rule)	Not applicable	Not applicable
	Nonpoint sources				
		Visible Emissions	Maximum opacity 40% (State Rule)	Not applicable	Maintain records of approved fugitive dust control plan

A. Crude Unit (Attachment “B” Section I)

1. Fuel Use in the Process Heaters

The Crude Unit includes two process heaters: the Atmospheric Crude Charge Heater and the Vacuum Crude Charge Heater. The Permittee is restricted to using RFG and natural gas in the process heaters, consistent with the information provided in the permit application, and heat input is limited to the maximum rates indicated in the permit application. These restrictions are needed to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department.

2. SO₂ Emissions from the Process Heaters

The process heaters are subject to limitations on fuel sulfur content, representing both BACT and applicable requirements under the NSPS (40 CFR 60 subpart J). The BACT and NSPS limits, respectively, are 35 ppmv sulfur (as H₂S) and 0.10 grains H₂S per dry standard cubic foot. The Permittee has two options for demonstrating compliance with these limitations: using a CEMS for SO₂ emissions as provided in Condition I.D.2 in Attachment “B” of the proposed permit or monitoring fuel sulfur content in accordance with Conditions XII.C.1 and XII.C.2 in Attachment “B” of the proposed permit. (The fuel sulfur content monitoring requirements are consolidated in Section XII of Attachment “B” of the proposed permit for administrative convenience.) If the fuel sulfur monitoring option is elected, the Permittee must demonstrate compliance with the NSPS limit by continuously monitoring fuel H₂S content and must demonstrate compliance with the BACT limit either by continuously monitoring fuel sulfur content or by periodically sampling and analyzing the fuel for total sulfur content and using these periodic data, in conjunction with the continuous H₂S monitoring data, to calculate fuel sulfur concentration.

The proposed permit includes SO₂ concentration levels that are deemed to be equivalent to the NSPS and BACT RFG sulfur concentration limits. Specifically, as provided by § 60.105(a)(3)(ii) of 40 CFR 60 subpart J, a stack gas SO₂ concentration level of 20 ppmv, dry basis, corrected to zero percent excess air, is deemed equivalent to the NSPS limit of 0.10 grains H₂S per dry standard cubic foot. A stack gas SO₂ concentration level of 4.3 ppmv, dry basis, corrected to zero percent excess air, is deemed equivalent to the BACT limit of 35 ppmv sulfur (as H₂S). If the Permittee chooses the SO₂ CEMS monitoring option for the NSPS and BACT RFG sulfur concentration limits, these SO₂ concentration levels will effectively become the applicable emission standards.

Each of the SO₂ concentration levels is established using an implicitly assumed ratio of 8.1 moles of stack gas (at zero percent excess air) per mole of RFG. The U.S. EPA's rationale for establishing this relationship between RFG sulfur and stack gas SO₂ is documented in an October 2, 1990, Federal Register notice (55 FR 40171). This ratio is conservative when compared to typical, actual RFG characteristics. For instance, if the actual RFG heat value is 1,000 British Thermal Units per standard cubic foot (Btu/scf) and the actual RFG F-factor is 8,700 dry standard cubic foot per million British Thermal Unit (dscf/MMBtu), both of which are fairly typical, 4.3 ppmv stack gas SO₂ concentration would correspond to an RFG sulfur level of 37.4 ppmv.

3. NO_x Emissions from the Process Heaters

Each of the process heaters is required to use both SCR and low-NO_x burners to control NO_x emissions, and each is subject to NO_x emission limits representing BACT.

The permit includes provisions for adjustment of the NO_x BACT limits for SCR-equipped process heaters after 24 months of operation. These provisions include either an automatic adjustment or, at the Permittee's option, provisions relating to an SCR performance demonstration study, the results of which may be used to adjust the NO_x BACT limit through a separate permitting action.

Compliance with the NO_x BACT emission limits is required to be demonstrated using CEMS. Each of these CEMS is required to meet the performance and quality assurance requirements of 40 CFR part 60, appendices B and F.

4. CO Emissions from the Process Heaters

Each of the process heaters is subject to CO emission limits representing BACT. Compliance with these emission limits is required to be demonstrated using CEMS. Each of these CEMS is required to meet the performance and quality assurance requirements of 40 CFR part 60, appendices B and F.

5. PM₁₀ Emissions from the Process Heaters

Each of the process heaters is subject to a PM₁₀ emission limit representing BACT. Compliance with these emission limits is required to be demonstrated through initial and annual performance tests.

6. Organic HAP Emissions from the Process Heaters

Each of the process heaters is subject to work practice standards,

expressed as CO emission limits, representing MACT for organic HAP emissions. Compliance with these emission limits is required to be demonstrated using CEMS.

7. Ammonia Emissions from the Atmospheric Crude Charge Heater

The Atmospheric Crude Charge Heater and Vacuum Crude Charge Heater SCR systems use ammonia as a reagent and are subject to ammonia emission limits representing BACT. Compliance with these emission limits are required to be demonstrated using CEMS. These CEMS are required to meet the quality assurance requirements of 40 CFR part 60, appendix F. There are no performance specifications for ammonia CEMS in appendix B to 40 CFR part 60, so the proposed permit requires that the Permittee include proposed performance specifications for these CEMS in the monitoring plan that must be submitted for the Director's approval.

8. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Crude Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment "B" of the proposed permit and are referenced in Condition I.B.8 of Attachment "B" of the proposed permit. These requirements are discussed in Section VI.X herein.

B. Gas Concentration Plant (Attachment "B" Section II)

1. NSPS Provisions for the Distillation Processes

The Gas Concentration Plant includes three distillation units: the De-Ethanizer Column, the Depropanizer Column, and the Debutanizer Column. The emission standards under 40 CFR 60 subpart NNN provide compliance options for these distillation units. The only permissible compliance option available to the Permittee is the routing of affected vent streams to process heaters, via the refinery fuel gas system, to reduce emissions of VOC (expressed as total organic compounds less methane and ethane) either by 98 percent or to an exhaust concentration of 20 ppmvd corrected to 3 percent oxygen. Other emission standards provided as compliance options are not permissible under the proposed refinery configuration. For example, routing the vent stream to a flare is an available compliance option under subpart NNN, but the flares at the proposed refinery are permitted to combust only emergency releases. Several provisions of subpart NNN pertaining to these unavailable compliance options have been omitted from the proposed permit to avoid the ambiguity that would result from their inclusion in the proposed permit.

The proposed permit, consistent with subpart NNN, requires

performance testing to demonstrate compliance with the VOC emission limit. This testing requirement applies to each process heater used to comply with the VOC emission limit, except for any process heater having a heat input capacity of 150 MMBtu/hr or greater. In addition, the proposed permit requires monitoring to ensure that the vent streams are routed into the process heaters and to ensure that each process heater, into which vent streams are routed, is operating. For process heaters of less than 150 MMBtu/hr heat input capacity, subject to the testing requirement described above, the temperature of the flame zone must be monitored and must be maintained at or above the level established during the performance test. Finally, the proposed permit provides for compliance with an alternative monitoring plan approved by the U.S. EPA, consistent with § 60.13 of 40 CFR 60 subpart A, in lieu of the monitoring procedures contained in the proposed permit.

2. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Gas Concentration Plant may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition II.B.2 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

C. Hydrocracker Unit (Attachment “B” Section III)

1. Process Heaters

The Hydrocracker Unit includes two process heaters: the Hydrocracker Unit Charge Heater and the Hydrocracker Main Fractionator Heater. Each of these heaters is required to use low-NO_x burners to control NO_x emissions. Refer to Sections VI.A.1 through VI.A.6 herein for a discussion of the requirements relating to fuel use in, visible emissions from, and emissions of SO₂, NO_x, CO, and PM₁₀ from the process heaters in the Hydrocracker Unit.

2. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Hydrocracker Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition III.B.7 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

D. Naphtha Hydrotreater Unit (Attachment “B” Section IV)

1. Process Heaters

The Naphtha Hydrotreater Unit includes one process heater: the Naphtha Hydrotreater Charge Heater. This heater is required to use low-NO_x burners to control NO_x emissions. Refer to Sections VI.A.1 through VI.A.6 herein for a discussion of the requirements relating to fuel use in, visible emissions from, and emissions of SO₂, NO_x, CO, and PM₁₀ from the Naphtha Hydrotreater Charge Heater.

2. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Naphtha Hydrotreater Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition IV.B.7 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

E. Catalytic Reforming Unit (Attachment “B” Section V)

1. NESHAP Provisions for the Catalyst Regenerator

The provisions of 40 CFR 63 subpart UUU that are applicable to catalytic reforming unit catalyst regenerators include emission standards both for organic HAPs and for inorganic HAPs. The control strategy to be used by the Permittee to comply with these emission standards consists of catalyst regenerator equipment design specifications and work practices in combination with the use of a caustic scrubber. Due to this proposed design configuration and control strategy, several of the compliance options provided by the regulation are not available to the Permittee. For example, routing the vent stream to a flare is an available compliance option for the organic HAP emission standards under subpart UUU, but the flares at the proposed refinery are permitted to combust only emergency releases, so the provisions relating to flares have been streamlined out of the proposed permit.

The applicable organic HAP emission standard under subpart UUU is expressed as a total organic compound (TOC) concentration level of 20 ppmv when the reactor vent pressure exceeds 5 psig. This emission standard also serves as the VOC BACT emission limit for this emission unit. The TOC concentration limit is included in Condition V.B.3.a(1) in Attachment “B” of the proposed permit.

The Permittee has indicated that the proposed catalyst regenerator equipment configuration and work practices would be sufficient to meet the TOC concentration limit even in the absence of the caustic scrubber. However, Subpart UUU also requires that the TOC concentration limit be met using a control device. Although the Permittee’s proposed equipment configuration is such that the scrubber

provides no quantifiable contribution toward compliance with the TOC concentration limit, this regulatory requirement is met due to the use of the caustic scrubber.

Subpart UUU does not provide operating limits or specific monitoring requirements that are adequate, for the Permittee's proposed equipment configuration, to provide assurance of continuous compliance with the organic HAP emission standard (i.e., the TOC concentration limit). For this reason, the Department is requiring that the Permittee maintain the ratio of perchloroethylene feed rate to catalyst circulation rate at a level equal to or lower than the level established during the initial performance test. In addition, Conditions V.D.5.a(1) and V.D.5.c require monitoring to demonstrate compliance with this work practice requirement.

The applicable inorganic HAP emission standard under subpart UUU includes two compliance options: a minimum required hydrogen chloride percent removal efficiency of 97 percent or a maximum allowable hydrogen chloride concentration level of 10 ppmvd, corrected to 3 percent oxygen. These compliance options are included in Condition V.B.3.b.1 in Attachment "B" of the proposed permit. The caustic scrubber work practice requirements from subpart UUU are included in Condition V.B.3.b(1) in Attachment "B" of the proposed permit.

Pursuant to subpart UUU and the NESHAP General Provisions, the proposed permit also includes a requirement to develop and implement a startup, shutdown, and malfunction plan and an operation, maintenance, and monitoring plan.

It should be noted that, at this time, the Department has neither requested nor been granted delegation of the U.S. EPA's authority to administer and enforce subpart UUU. Thus, citations of the authority for permit terms relating to subpart UUU are to 40 CFR part 63 rather than A.A.C. R18-2-1101. For this reason, all reporting requirements under subpart UUU are required to be submitted to both the Department and the U.S. EPA.

2. Catalyst Regenerator Visible Emissions

The Catalytic Reforming Unit Catalyst Regenerator is subject to A.A.C. R18-2-702(B) for visible emissions. The applicable 20 percent opacity limit is included in the proposed permit. Because only gaseous emissions are expected from the Catalyst Regenerator due to process design, compliance with the applicable opacity standard under this regulation is presumed under all operating conditions. Therefore, no monitoring is required.

3. Catalyst Regenerator NO_x Emissions

The catalyst regenerator is subject to a NO_x emission limit representing BACT. Compliance with this emission limit is required to be demonstrated by conducting initial and annual performance tests using EPA Reference Method 7 or 7E from appendix A to 40 CFR part 60.

4. Catalyst Regenerator CO Emissions

The catalyst regenerator is subject to a CO emission limit representing BACT. Compliance with this emission limit is required to be demonstrated by conducting initial and annual performance tests using EPA Reference Method 10 or 10 B from appendix A to 40 CFR part 60.

5. Process Heaters

The Catalytic Reforming Unit includes four process heaters: the Catalytic Reforming Unit Charge Heater, Catalytic Reforming Unit Interheater Nos. 1 and 2, and the Catalytic Reforming Unit Debutanizer Reboiler. The Debutanizer Reboiler is required to use low-NO_x burners to control NO_x emissions; the other three heaters are required to use low-NO_x burners and SCR to control NO_x emissions.

Refer to Sections VI.A.1 through VI.A.6 herein for a discussion of the requirements relating to fuel use in, visible emissions from, and emissions of SO₂, NO_x, CO, and PM₁₀ from the process heaters in the Catalytic Reforming Unit. In addition, refer to Section VI.A.7 herein for a discussion of the requirements relating to emissions of ammonia from the heaters that are equipped with SCR (i.e., the Charge Heater and Interheater Nos. 1 and 2).

6. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Catalytic Reforming Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment "B" of the proposed permit and are referenced in Condition V.B.4 of Attachment "B" of the proposed permit. These requirements are discussed in Section VI.X herein.

F. Isomerization Unit (Attachment "B" Section VI)

The piping components in the Isomerization Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The only requirements pertaining to this process unit are those for this equipment. These requirements are consolidated in Section XXIV of Attachment "B" of the proposed permit and are referenced in Condition VI.B of Attachment "B" of the proposed permit. These requirements are discussed in Section VI.X

herein.

G. Distillate Hydrotreater Unit (Attachment “B” Section VII)

1. Process Heaters

The Distillate Hydrotreater Unit includes two process heaters: the Distillate Hydrotreater Charge Heater and the Distillate Hydrotreater Splitter Reboiler. Each of these heaters is required to use low-NO_x burners to control NO_x emissions. Refer to Sections VI.A.1 through VI.A.6 herein for a discussion of the requirements relating to fuel use in, visible emissions from, and emissions of SO₂, NO_x, CO, and PM₁₀ from the process heaters in the Distillate Hydrotreater Unit.

2. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Distillate Hydrotreater Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition VII.B.7 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

H. Butane Conversion Unit (Attachment “B” Section VIII)

1. NSPS Provisions for the Distillation Units

The Butane Conversion Unit includes two distillation units: the Isostripper Column and the Stabilizer Column. Refer to Section VI.B.1 herein for a discussion of the requirements relating to VOC emissions from these distillation units.

2. NSPS Provisions for the Reactor Processes

The Butane Conversion Unit includes three reactor processes: the Butamer Reactor, the Dehydrogenation Reactor, and the Catalytic Condensation Reactor. The emission standards under 40 CFR 60 subpart RRR provide compliance options for these reactor processes. The only permissible compliance option available to the Permittee is the routing of affected vent streams to process heaters, via the refinery fuel gas system, to reduce emissions of VOC (expressed as total organic compounds less methane and ethane) either by 98 percent or to an exhaust concentration of 20 ppmvd corrected to 3 percent oxygen. Other emission standards provided as compliance options are not permissible under the proposed refinery configuration. For example, routing the vent stream to a flare is an available compliance option under subpart RRR, but the flares at the proposed refinery are permitted to combust only emergency releases. Several provisions of subpart RRR pertaining to these unavailable compliance options have

been omitted from the proposed permit to avoid the ambiguity that would result from their inclusion in the proposed permit. In light of the requirement for venting the reactor process vent streams to process heaters, via the refinery fuel gas system, the proposed permit, consistent with subpart RRR, does not require any performance testing to demonstrate compliance with the VOC emission limit. The only monitoring requirement is for monitoring of bypass piping that could divert the vent streams away from the process heaters.

3. Catalyst Regenerator Visible Emissions

The Butane Conversion Unit Catalyst Regenerator is subject to A.A.C. R18-2-702(B) for visible emissions. The applicable 20 percent opacity limit is included in the proposed permit. Because only gaseous emissions are expected from the Catalyst Regenerator due to process design, compliance with the applicable opacity standard under this regulation is presumed under all operating conditions. Therefore, no monitoring is required.

4. Catalyst Regenerator NO_x Emissions

The catalyst regenerator is subject to a NO_x emission limit representing BACT. Compliance with this emission limit is required to be demonstrated by conducting initial and annual performance tests using EPA Reference Method 7 or 7E from appendix A to 40 CFR part 60.

5. Catalyst Regenerator CO Emissions

The catalyst regenerator is subject to a CO emission limit representing BACT. Compliance with this emission limit is required to be demonstrated by conducting initial and annual performance tests using EPA Reference Method 10 or 10 B from appendix A to 40 CFR part 60.

6. Process Heaters

The Butane Conversion Unit includes three process heaters: the Butane Conversion Unit Dehydrogenation Reactor Charge Heater, the Butane Conversion Unit Dehydrogenation Reactor Interheater, and the Butane Conversion Unit Isostripper Reboiler. Each of these heaters is required to use low-NO_x burners and SCR to control NO_x emissions.

Refer to Sections VI.A.1 through VI.A.7 herein for a discussion of the requirements relating to fuel use in, visible emissions from, and emissions of SO₂, NO_x, CO, PM₁₀, and ammonia from the process heaters in the Butane Conversion Unit.

7. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Butane Conversion Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition VIII.B.6 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

I. Benzene Reduction Unit (Attachment “B” Section IX)

The piping components in the Benzene Reduction Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The only requirements pertaining to this process unit are those for this equipment. These requirements are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition IX.B of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

J. Delayed Coking Unit (Attachment “B” Section X)

1. Process Heaters

The Delayed Coking Unit includes two process heaters: Delayed Coking Unit Charge Heater Nos. 1 and 2. Each of these heaters is required to use low-NO_x burners to control NO_x emissions. Refer to Sections VI.A.1 through VI.A.6 herein for a discussion of the requirements relating to fuel use in, visible emissions from, and emissions of SO₂, NO_x, CO, and PM₁₀ from the process heaters in the Delayed Coking Unit.

2. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Delayed Coking Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition X.B.7 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

K. Petroleum Coke Storage, Handling, and Loading (Attachment “B” Section XI)

1. Prohibition of Visible Emissions

The Permittee is required to conduct all coke handling operations in a manner such that there are no visible emissions across the property boundary. In addition, the proposed permit prohibits any visible emissions from the Coke Crusher, the Coke Conveyor, the Coke Silo, and the Coke Rail Car Loading operation. The proposed permit

requires once-per-shift visible emissions observations to ensure compliance with these requirements.

2. Coke Moisture Content

The Permittee is required to maintain the coke moisture content at a level of at least 12 percent by weight in order to minimize fugitive particulate matter emissions from coke handling operations. The proposed permit requires daily sampling and analysis of coke from five specified locations to ensure compliance with this requirement.

3. Coke Pit and Coke Pad Equipment Design

The proposed permit restricts the size of the Coke Pit and Coke Pad to a maximum combined surface area of 48,000 square feet. The proposed permit also requires that the Coke Pit and Coke Pad be maintained within a completely walled enclosure and that all coke handling operations be conducted in a manner such that all operations occur at least five feet below the lowest point on the top of the walled enclosure. The proposed permit requires once-per-shift recording of the height of coke piles to ensure compliance with this requirement.

4. Coke Crusher Equipment Design

The Coke Crusher handles wet material that crushes readily and is not expected to have any fugitive emissions under most operating conditions. Nonetheless, the proposed permit requires that the crusher be located within the walled enclosure around the Coke Pit and Coke Pad. The proposed permit further requires that the Coke Crusher be designed and maintained with a partial enclosure (i.e., sides and a top) to prevent the coke from being entrained by wind under windy conditions.

5. Coke Conveyor Equipment Design

The proposed permit allows the use of only one Coke Conveyor, extending from the Coke Crusher to the Coke Silo. This Coke Conveyor handles wet material and is not expected to have any fugitive emissions under most operating conditions. Nonetheless, the proposed permit requires that the conveyor be fully enclosed, with only two transfer points.

6. Coke Silo

The proposed permit requires that the Coke Silo be fully enclosed and equipped with a baghouse. The Coke Silo Baghouse is subject to a PM₁₀ emission limit of 0.005 gr/dscf representing BACT. Compliance with this emission limit is required to be demonstrated through initial and annual performance tests.

7. Coke Rail Car Loading

The proposed permit requires that the Coke Rail Car Loading operation be conducted within an enclosure and that the enclosure be equipped with overlapping flaps or sliding doors on the openings through which rail cars enter and exit the enclosure. The proposed permit further requires that the loading operation be conducted using a telescoping chute to ensure that the height of the coke drop does not exceed four feet.

L. Amine Regeneration Unit (Attachment “B” Section XII)

1. Provisions for Minimizing Excess SO₂ Emissions

The Amine Regeneration Unit serves to regenerate “rich” amine solution (i.e., amine solution with a high level of sulfur) by removing sulfur compounds to produce “lean” amine solution. The lean amine solution is returned to the amine contactors that are used to remove hydrogen sulfide and other reduced sulfur compounds from RFG streams. The rich amine solution exiting the amine absorbers is recycled to the Amine Regeneration Unit, beginning the cycle again. The “sour gas” (i.e., hydrogen sulfide-rich gas) exiting the Amine Regeneration Unit is routed to the Sulfur Recovery Plant as feed material.

The ability of the amine absorbers to remove sulfur from RFG is limited by the supply of lean amine solution and by the availability of an outlet for rich amine solution. The outlet for rich amine solution is normally the Amine Regeneration Unit but, in the event of an upset or malfunction, the Rich Amine Tank serves as the outlet.

Some of the refinery processes that produce RFG streams cannot be safely shut down in a short period of time. There is no safe alternative to combusting these streams. In the event of an upset or malfunction that renders one or more amine absorbers inoperable, the removal of sulfur from the RFG streams will be diminished, and excess SO₂ emissions from RFG combustion devices are likely. Similarly, in the event of an upset or malfunction of the Sulfur Recovery Plant, the sour gas exiting the Amine Regeneration Unit must be combusted in a flare or thermal oxidizer.

The proposed permit imposes equipment design and work practice requirements that will minimize the excess SO₂ emissions that could occur as a result of upset or malfunction. Specifically, the proposed permit requires that rich amine shall be re-routed to the Rich Amine Tank and acid gas flaring shall be ceased within fifteen minutes after the start of the acid gas flaring or other upset that results in excess emissions. In addition, the proposed permit requires that the Permittee

maintain a full day's supply of lean amine solution (210,000 gallons) and a full day's available storage capacity for rich amine solution (210,000 gallons). Taken together, these requirements will allow the amine absorbers to function properly for a period of at least 24 hours in the event of an upset at the Amine Regeneration Unit or the Sulfur Recovery Plant. During that period, the sulfur that would otherwise be emitted as excess SO₂ emissions from the RFG combustion devices, the thermal oxidizer, or the emergency flare is instead stored in rich amine solution being temporarily accumulated in the Rich Amine Tank.

The proposed permit includes terms requiring that records of amine solution throughput be maintained, that the available supply of lean amine solution be at least a specified amount, and that the available rich amine storage capacity be at least the same specified amount. Taken together, these terms will allow the Permittee to demonstrate compliance with the requirements for a full day's supply of lean amine solution and a full day's available storage capacity for rich amine solution.

In the event that the upset cannot be resolved before the available storage capacity for rich amine solution is exhausted, the proposed permit includes a requirement that production at upstream process units be curtailed in order to minimize excess SO₂ emissions.

2. Monitoring Provisions for RFG Sulfur Content

As noted in Section VI.A.2 herein, all RFG-fired process heaters are subject to limitations on fuel sulfur content, representing both BACT and applicable requirements under the NSPS (40 CFR 60 subpart J). In lieu of using SO₂ CEMS to demonstrate compliance with these limitations, the Permittee has the option of monitoring fuel sulfur content. These optional fuel sulfur content monitoring requirements are consolidated in Section XII of Attachment "B" of the proposed permit. This is done for administrative convenience, because the amine contactors associated with the Amine Regeneration Unit are the primary means of removing sulfur compounds from the RFG prior to combustion.

3. NESHAP Provisions for the Rich Amine Three Phase Separator

The vent stream from the Rich Amine Three Phase Separator is subject to the requirements for miscellaneous process vents under 40 CFR 63 subpart CC. These requirements are included in the proposed permit. The Permittee is required to comply by routing the vent stream to the Sulfur Recovery Plant Thermal Oxidizer for control of VOC emissions. The proposed permit also includes testing, monitoring, and recordkeeping provisions consistent with subpart CC, including monitoring of bypass lines that could divert the vent stream away from

the Thermal Oxidizer. Requirements specific to the operation of the Thermal Oxidizer are contained in Section XIV of Attachment “B” of the proposed permit and are discussed in Section VI.N.3 herein.

4. Rich Amine and Lean Amine Tanks

As noted in Section IV.C.8 herein, the rich amine and lean amine tanks are classified as Group 2 Storage Vessels under 40 CFR 63 subpart CC, due to the low vapor pressure of the materials that are proposed to be stored in these tanks. The proposed permit includes the subpart CC requirement, applicable to all Group 2 Storage Vessels, for maintaining records of tank dimensions and capacity. In addition, the proposed permit includes a limit of 3.4 kPa on the maximum true vapor pressure of materials stored in the rich amine and lean amine tanks, and a requirement to maintain records of the true vapor pressure of the materials stored in these tanks. These requirements are designed to ensure that the non-applicability of the more stringent requirements for Group 1 Storage Vessels under subpart CC is maintained continuously.

5. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Amine Regeneration Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition XII.B.2 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

M. Sour Water Stripper (Attachment “B” Section XIII)

1. Provisions for Minimizing Excess SO₂ Emissions

The Sour Water Stripper serves to remove sulfur compounds and other contaminants from refinery process wastewater. Some of the refinery processes that produce sour water streams cannot be safely shut down in a short period of time. In the event of an upset or malfunction of the Sulfur Recovery Plant, sour gas exiting the Sour Water Stripper must be combusted in a flare or thermal oxidizer.

The proposed permit imposes equipment design requirements that will minimize the excess SO₂ emissions that could occur as a result of upset or malfunction. Specifically, the proposed permit requires that sour water shall be re-routed to the Sour Water Tank and acid gas flaring shall be ceased within fifteen minutes after the start of the acid gas flaring or other upset that results in excess emissions. In addition, the proposed permit requires that the Permittee maintain a full day’s available storage capacity for sour water (3.78 million gallons). Taken together, these requirements will allow the refinery to operate for a

period of at least 24 hours in the event of an upset at the Sulfur Recovery Plant. During that period, the sulfur that would otherwise be emitted as excess SO₂ emissions from the thermal oxidizer or the emergency flare is instead stored in sour water being temporarily accumulated in the Sour Water Tank.

The proposed permit includes conditions requiring that records of sour water throughput be maintained and that the available sour water storage capacity be at least a specified amount. Taken together, these terms will allow the Permittee to demonstrate compliance with the requirement for a full day's available storage capacity for sour water.

In the event that the upset cannot be resolved before the available storage capacity for sour water is exhausted, the proposed permit includes a requirement that production at upstream process units be curtailed in order to minimize excess SO₂ emissions.

2. NESHAP Provisions for the Sour Water Flash Drum

The vent stream from the Sour Water Flash Drum is subject to the requirements for miscellaneous process vents under 40 CFR 63 subpart CC. These requirements are included in the proposed permit. The Permittee is required to comply by routing the vent stream to the Sulfur Recovery Plant Thermal Oxidizer for control of VOC emissions. The proposed permit also includes testing, monitoring, and recordkeeping provisions consistent with subpart CC, including monitoring of bypass lines that could divert the vent stream away from the Thermal Oxidizer. Requirements specific to the operation of the Thermal Oxidizer are contained in Section XIV of Attachment "B" of the proposed permit and are discussed in Section VI.N.3 herein.

3. NSPS Provisions for Sour Water Tank

As noted in Section IV.B.7 herein, the Sour Water Tank is subject to the provisions of 40 CFR 60 subpart Kb. The Permittee has elected to comply with subpart Kb using a fixed roof in combination with an internal floating roof. This compliance option is available because the maximum true vapor pressure of the materials proposed to be stored in this tank is less than 76.6 kPa. The proposed permit includes the subpart Kb requirements for the chosen compliance option, including the use of a dual seal closure device; performing and maintaining records of floating roof inspections; maintaining records of tank dimensions and capacity; and maintaining records of the maximum true vapor pressure of materials stored in the tank. In addition, the proposed permit includes a limit of 76.6 kPa on the maximum true vapor pressure of materials stored in the tank. This requirement is designed to ensure that the more stringent requirements under subpart Kb, applicable to tanks storing highly volatile materials, are not applicable to the Sour Water Tank.

4. H₂S Emission Standard for Sour Water Tank

In addition to the NSPS requirements pertaining to the use of an internal floating roof, the Sour Water Tank is also required to be equipped with a dual-canister carbon adsorption system representing BACT for emissions of H₂S. In addition, the Permittee is required to perform continuous monitoring of the exhaust stream for breakthrough.

5. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Sour Water Stripper may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment "B" of the proposed permit and are referenced in Condition XIII.B.3 of Attachment "B" of the proposed permit. These requirements are discussed in Section VI.X herein.

N. Sulfur Recovery Plant (Attachment "B" Section XIV)

1. NSPS and NESHAP Provisions for SO₂ Emissions from the Thermal Oxidizer

The emission standards under 40 CFR 60 subpart J and 40 CFR 63 subpart UUU are essentially identical. Each of these regulations provides several compliance options. The only permissible compliance option available to the Permittee is to meet the exhaust gas SO₂ concentration standard of 250 ppmvd, corrected to 0.0 percent oxygen, using a TGTU and a thermal oxidizer. Other emission standards provided as compliance options in subpart J and subpart UUU are not permissible under the proposed refinery configuration. Several provisions of subpart J and subpart UUU pertaining to these unavailable compliance options have been streamlined out of the proposed permit.

The proposed permit requires use of an SO₂ CEMS, including an oxygen monitor, to demonstrate compliance with the SO₂ emission limit. There is a minor discrepancy between the monitoring provisions of subpart J and subpart UUU. Under § 60.105(a)(5)(i) of subpart J, the oxygen monitor span value is specified as 25 percent oxygen (O₂). (Prior to a regulatory revision promulgated on October 17, 2000, this value was specified as 10 percent O₂.) Under § 63.1572(a)(1) of subpart UUU, promulgated on April 11, 2002, the span value for the same instrument is specified as 10 percent O₂. The Department has used its discretion in specifying a span value of 10 percent O₂ for the oxygen monitor.

It should be noted that the Department has neither requested nor been granted delegation of the U.S. EPA's authority to administer and

enforce subpart UUU. Thus, citations of the authority for permit terms relating to subpart UUU are to 40 CFR part 63 rather than A.A.C. R18-2-1101. For this reason, all reporting requirements under subpart UUU are required to be submitted to both the Department and the U.S. EPA.

2. BACT Emission Limits for SO₂ and Reduced Sulfur Compounds from the Thermal Oxidizer

The BACT emission limits for SO₂ and reduced sulfur compound emissions from the Sulfur Recovery Plant Thermal Oxidizer are included in Conditions XIV.B.2.b and XIV.B.4.a, respectively, in Attachment “B” of the proposed permit. The SO₂ BACT emission limit is expressed in lb/hr, based on a rolling one-hour averaging time. Although this emission limit is expected to be much more stringent than the NSPS SO₂ emission limit, described above, the NSPS limit has not been streamlined out of the proposed permit because it is possible that it could be more stringent under some operating conditions. The proposed permit requires use of an SO₂ CEMS, including an oxygen monitor, to demonstrate compliance with the SO₂ BACT emission limit.

As described in detail in Section V.C.2 herein, the BACT emission limit for reduced sulfur compounds covers three separate PSD-regulated pollutants that are practically equivalent for petroleum refinery sulfur recovery plants. The BACT emission limit for reduced sulfur compounds, as defined in Condition XIV.B.4.b in Attachment “B” of the proposed permit, is expressed in terms of total emissions of the three compounds that are expected to account for nearly all reduced sulfur compounds emissions from the thermal oxidizer: hydrogen sulfide, carbonyl sulfide, and carbon disulfide.

3. BACT and NESHAP Provisions for VOC Emissions from the Thermal Oxidizer

As noted in Sections VI.L.3 and VI.M.2 herein, respectively, the proposed permit requires that the vent streams from the Rich Amine Three Phase Separator and the Sour Water Flash Drum be routed to the Sulfur Recovery Plant Thermal Oxidizer in order to comply with the requirements for miscellaneous process vents under 40 CFR 63 subpart CC. The subpart CC requirements for the Thermal Oxidizer are included in Section XIV of Attachment “B” of the proposed permit. The VOC emission standard requires that the Thermal Oxidizer reduce emissions of VOC (expressed as total organic compounds less methane and ethane) either by 98 percent or to an exhaust concentration of 20 ppmvd corrected to 3 percent oxygen, whichever is less stringent. The proposed permit, consistent with subpart CC, also includes requirements for conducting an initial performance test to demonstrate compliance with the VOC emission standard and to establish a minimum Thermal Oxidizer combustion chamber temperature. In

order to satisfy BACT requirements, the proposed permit also includes requirements for maintaining the Thermal Oxidizer exhaust gas volumetric flow rate at or below the level that corresponds to a minimum combustion chamber residence time of 0.75 seconds. Finally, the proposed permit includes monitoring and recordkeeping requirements to ensure compliance with the minimum combustion chamber temperature requirement.

4. Thermal Oxidizer NO_x Emissions

The Sulfur Recovery Plant Thermal Oxidizer is required to use low-NO_x burners to control NO_x emissions and is subject to a NO_x BACT emission limit of 0.06 lb/MMBtu. With the exception of the unit-specific BACT emission limit, the proposed permit conditions, including monitoring, recordkeeping, reporting, and testing requirements, are consistent with those contained in other sections of the proposed permit involving RFG combustion units. See Section VI.A of this document for a more detailed discussion of the proposed permit conditions relating to NO_x emissions from combustion sources.

5. Thermal Oxidizer CO Emissions

The Sulfur Recovery Plant Thermal Oxidizer must be designed and operated to achieve stringent NESHAP and BACT limitations and standards for VOC and organic HAPs as required in the proposed permit. Based on this, it can be assumed that the oxidizer will operate with inherently complete combustion and minimal CO emissions. The proposed permit does not contain specific CO emission limitations or standards for the Sulfur Recovery Plant Thermal Oxidizer. The design and operational requirements for VOC and HAP control and associated monitoring, recordkeeping, and reporting provisions were deemed sufficient for the purpose of minimizing CO emissions.

6. Sulfur Pits

Consistent with the BACT determination for hydrogen sulfide emissions, as discussed in Section V.D herein, the proposed permit requires that the exhaust gases from Sulfur Pit Nos. 1 and 2 and routed to the inlet of either Sulfur Recovery Unit No. 1 or Sulfur Recovery Unit No. 2.

7. MDEA Tank

As noted in Section IV.C.8 herein, the MDEA Tank is classified as a Group 2 Storage Vessel under 40 CFR 63 subpart CC, due to the low vapor pressure of the materials that are proposed to be stored in this tank. The proposed permit includes the subpart CC requirement, applicable to all Group 2 Storage Vessels, for maintaining records of tank dimensions and capacity. In addition, the proposed permit

includes a limit of 3.4 kPa on the maximum true vapor pressure of materials stored in the MDEA Tank, and a requirement to maintain records of the true vapor pressure of the materials stored in this tank. These requirements are designed to ensure that the non-applicability of the more stringent requirements for Group 1 Storage Vessels under subpart CC is maintained continuously.

8. Sulfur Product Truck and Rail Car Loading Racks

Consistent with the BACT determination for hydrogen sulfide emissions, as discussed in Section V.E herein, the proposed permit requires that the liquid sulfur be degassed to a maximum hydrogen sulfide concentration of 15 ppmw before being loaded into trucks or rail cars. The proposed permit includes requirements for daily sampling and analysis of the H₂S content in the sulfur stored in the sulfur pits to determine compliance with this limitation.

9. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Sulfur Recovery Unit may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition XIV.B.8 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

O. Hydrogen Plant (Attachment “B” Section XV)

1. Process Heater

The Hydrogen Plant includes one process heater: the Hydrogen Reformer Heater. This heater is required to use low-NO_x burners and SCR to control NO_x emissions. Refer to Sections VI.A.1 through VI.A.7 herein for a discussion of the requirements relating to fuel use in, visible emissions from, and emissions of SO₂, NO_x, CO, PM₁₀, and ammonia from the Hydrogen Reformer Heater.

2. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Hydrogen Plant may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition XV.B.8 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

P. Group “A” Storage Tanks (Attachment “B” Section XVI)

1. VOC and HAP Provisions

Group “A” Storage Tanks, which consist of eight dome-roof storage vessels with emissions routed to the RFG system, are subject to BACT requirements for VOC emissions and to the petroleum refinery NESHAP [40 CFR 63.646; §§ 63.119 - 63.121, by reference] for HAP emissions. The applicable provisions of § 63.119(f) of 40 CFR part 63 were incorporated into the proposed permit. BACT requirements are noted by citation. See Section V.F of this document for information on the BACT analysis for the storage tanks.

Pursuant to A.A.C. R18-2-406(A)(4) [BACT] and NESHAP requirements for new sources [40 CFR 63.646; § 63.119(f), by reference], vapors from all Group “A” Storage Tanks must be collected in a closed-vent hard pipe system and routed to a vapor compression system. Gases collected in the vapor compression system must be introduced into the RFG system. The conditions in Section XVI.B of Attachment “B” of the proposed permit closely follow the regulatory provisions of 40 CFR 63.119(f).

Monitoring, recordkeeping, and reporting conditions are consistent with the requirements of 40 CFR 63.654 and 40 CFR 63.123, by reference, as applicable. No specific testing requirements apply. However, the test methods contained in 40 CFR 63 Subpart CC do apply.

Finally, the proposed permit includes requirements for tank degassing and cleaning, consistent with the BACT determination for storage tank VOC emissions as discussed in Section V.F.1 herein. These include a requirement to control degassing emissions using liquid balancing, incineration, condensation, or another control method subject to prior approval by the Director. The recordkeeping requirements in the proposed permit, pertaining to tank degassing and cleaning operations, include requirements for maintaining records of tank identification and capacity; records of the material stored; records of the flow rate and VOC concentration of gases vented to the degassing equipment; records of the total amount of VOC processed in the degassing equipment; records of the control efficiency of the degassing equipment; and records of the degassing equipment operating parameters, specific to the type of degassing equipment being used.

2. Equipment in VOC and Organic HAP Service

The piping components associated with the Group “A” Storage Tanks may include equipment in VOC and organic HAP service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition XVI.B.10 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

Q. Group “B” Storage Tanks (Attachment “B” Section XVII)

1. VOC and HAP Provisions

Group “B” Storage Tanks, which consist of 47 fixed roof storage vessels equipped with fixed and internal floating roofs and controlled by the Tank Farm Thermal Oxidizer, are subject to BACT requirements for VOC emissions and to the petroleum refinery NESHAP [40 CFR 63.646; §§ 63.119 - 63.121, by reference] for HAP emissions. The applicable provisions of § 63.119(e) of 40 CFR part 63 were incorporated into the proposed permit. Additional and more stringent requirements apply to the Thermal Oxidizer for the purpose of BACT, as noted by citation. See Section V.F of this document for information on the BACT analysis for the storage tanks.

Pursuant to A.A.C. R18-2-406(A)(4) [BACT] and NESHAP requirements for new sources [40 CFR 63.646; § 63.119(e) by reference], all Group “B” storage tanks must be equipped with an internal floating roof and head space emissions must be collected in a closed-vent system and routed to the Tank Farm Thermal Oxidizer. The conditions in Section XVI.B of Attachment “B” of the proposed permit incorporate the regulatory provisions of 40 CFR 63.119(e). Additionally, the provisions of 40 CFR 63.119(b), (HON for storage vessels - reference control technology: fixed roof tank with internal floating roof) were incorporated for the purpose of BACT for VOC emissions. For the Tank Farm Thermal Oxidizer, VOC BACT emission limitations are design standards and operational requirements including minimum design VOC destruction efficiency (≥ 99.9 percent at inlet VOC concentrations exceeding 20,000 ppmv), minimum combustion chamber temperature (≥ 1600 °F), and maximum exhaust gas volumetric flow rate corresponding to a minimum residence time (≥ 0.75 second).

Monitoring, recordkeeping, and reporting conditions include the compliance determination procedures of 40 CFR 63.120(d) and additional specific BACT monitoring requirements for the Tank Farm Thermal Oxidizer. In addition to the Thermal Oxidizer design evaluation and monitoring plan required under 40 CFR 63.120(d), the Tank Farm Thermal Oxidizer must be equipped with a continuous combustion chamber temperature monitoring system. Excess emissions for the purpose of BACT are defined as each 5-minute block during which the thermal oxidizer combustion chamber outlet temperature falls below the required minimum or the exhaust gas volumetric flow rate exceeds the specified maximum. An annual inspection of the thermal oxidizer burner and temperature monitoring system is also required.

Because the VOC BACT emission limits/standards for the Tank Farm Thermal Oxidizer are expressed in terms of control device

design/operation parameters (temperature and flow rate), and continuous monitoring of these parameters is specified as a proposed permit condition, CAM requirements are not applicable per the exemption provided in 40 CFR 64.4(b)(vi).

The petroleum refinery NESHAP (40 CFR 63 subpart CC) allows for up to 240 hours per year of scheduled maintenance downtime, during which the Thermal Oxidizer is not required to achieve 95 percent HAP control efficiency. The same variance allowance is provided in the proposed permit for the purpose of VOC BACT. This is justified because, for the tank farm operations, control device maintenance cannot be performed during scheduled equipment outages.

NESHAP recordkeeping and reporting conditions are consistent with the requirements of 40 CFR 63.654(f), (g), and (h) and 40 CFR 63.123, by reference in 40 CFR 63.654(i), as applicable. No specific testing requirements apply. However, the test methods contained in 40 CFR 63 Subpart CC do apply.

Finally, the proposed permit includes requirements for tank degassing and cleaning, consistent with the BACT determination for storage tank VOC emissions as discussed in Section V.F.1 herein. These include a requirement to control degassing emissions using liquid balancing, incineration, condensation, or another control method subject to prior approval by the Director. The recordkeeping requirements in the proposed permit, pertaining to tank degassing and cleaning operations, include requirements for maintaining records of tank identification and capacity; records of the material stored; records of the flow rate and VOC concentration of gases vented to the degassing equipment; records of the total amount of VOC processed in the degassing equipment; records of the control efficiency of the degassing equipment; and records of the degassing equipment operating parameters, specific to the type of degassing equipment being used.

2. Thermal Oxidizer Operational Limitations

The Permittee is restricted to using RFG and natural gas in the Tank Farm Thermal Oxidizer, consistent with the information provided in the permit application. This restriction is necessary to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department.

The proposed permit does not include any enforceable limitation on the heat input to the Tank Farm Thermal Oxidizer. The sole function of the thermal oxidizer is to control emissions of VOC and organic HAPs; the Permittee has no economic incentive to operate the device at a heat input rate that is higher than necessary to achieve adequate control efficiency. A heat input limit would generally provide

disincentive to the Permittee to operate the thermal oxidizer at higher control efficiencies. The emissions of VOC and organic HAP due to insufficient temperature in the thermal oxidizer are substantial; the emissions of combustion-generated pollutants are relatively small. The Department evaluated whether a heat input limit is appropriate and determined that the only possible benefit would be improved tracking of PM₁₀ emissions. (Tracking the emissions of other combustion-generated pollutants would be unaffected. Emissions of SO₂ and NO_x are subject to continuous monitoring, and emissions of VOC and CO are inversely related to the thermal oxidizer heat input rate.)

The Department concluded that this benefit is significantly outweighed by the potentially greater adverse environmental impacts that would result. Also, it is unlikely that the heat input will exceed the 53 MMBtu/hr rate that was indicated in the permit application. This value is based on an engineering design evaluation of the heat requirements for maintaining the required thermal oxidizer combustion chamber temperature, assuming a gas flow that reflects the simultaneous maximum rate of displacement from all Group "B" Storage Tanks. This is a conservative method of estimating required heat input rate to the thermal oxidizer.

3. Thermal Oxidizer SO₂ Emissions

The Tank Farm Thermal Oxidizer is subject to NSPS (40 CFR 60 subpart J) and BACT requirements for SO₂ emissions. The proposed permit conditions, including emission limits and standards, monitoring, recordkeeping, reporting, and testing requirements, are consistent with those contained in other sections of the proposed permit involving RFG combustion units. See Sections V.B.2 and VI.A of this document for a more detailed discussion of SO₂ BACT and proposed permit conditions for RFG combustion sources.

4. Thermal Oxidizer PM₁₀ Emissions

The Tank Farm Thermal Oxidizer is subject to a PM₁₀ BACT emission limit of 0.0075 lb/MMBtu. The proposed permit conditions, including emission limits/standards, monitoring, recordkeeping, reporting, and testing requirements, are consistent with those contained in other sections of the proposed permit involving RFG combustion units. See Sections V.B.1 and VI.A of this document for a more detailed discussion of PM₁₀ BACT and proposed permit conditions for RFG combustion sources.

5. Thermal Oxidizer NO_x Emissions

The Tank Farm Thermal Oxidizer is subject to a NO_x BACT emission limit of 0.04 lb/MMBtu. With the exception of the unit-specific BACT emission limit, the proposed permit conditions, including monitoring,

recordkeeping, reporting, and testing requirements, are consistent with those contained in other sections of the proposed permit involving RFG combustion units. See Section VI.A of this document for a more detailed discussion of the proposed permit conditions relating to NO_x emissions from combustion sources.

6. Thermal Oxidizer CO Emissions

The Tank Farm Thermal Oxidizer must be designed and operated to achieve stringent NESHAP and BACT limitations and standards for VOC and organic HAPs as required in the proposed permit. Based on this, it can be assumed that the oxidizer will operate with inherently complete combustion and minimal CO emissions. The proposed permit does not contain specific CO emission limitations or standards for the Tank Farm Thermal Oxidizer. The design and operational requirements for VOC and HAP control and associated monitoring, recordkeeping, and reporting provisions were deemed sufficient for the purpose of minimizing CO emissions.

7. Equipment in VOC and Organic HAP Service

The piping components associated with the Group “B” Storage Tanks may include equipment in VOC and organic HAP service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition XVII.B.8 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

R. Group “D” Storage Tanks (Attachment “B” Section XIX)

1. VOC and HAP Provisions

Group “D” Storage Tanks, which consist of six pressure vessels designed to operate with zero emissions, are categorically exempt from NESHAP (40 CFR 63 subpart CC) requirements. To meet NESHAP exemption criteria and BACT requirements, all Group “D” Storage Tanks must be designed to operate in excess of 204.9 kPa without emissions to the atmosphere. The definition of “storage vessel” in subpart CC (40 CFR 63.641) specifically excludes “pressure vessels designed to operate in excess of 204.9 kPa without emissions to the atmosphere.”

Monitoring, recordkeeping, and reporting conditions include requirements to maintain operating pressure records for the purpose of BACT and the voluntarily accepted minimum pressure requirement.

2. Equipment in VOC and Organic HAP Service

The piping components associated with the Group “D” Storage Tanks

may include equipment in VOC and organic HAP service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition XIX.B.3 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

S. Group “E” Storage Tank (Attachment “B” Section XX)

1. Visible Emissions

A single storage tank, Asphalt Tank T-42801, comprises the Group “E” Storage Tank category. The asphalt storage tank is subject to the requirements of 40 CFR 60 subpart UU. Section 60.472(c) of subpart UU requires that asphalt tanks be operated with zero visible emissions (opacity) to the atmosphere, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for cleaning. Pursuant to BACT, the tank exhaust must be cooled to below 120° F and vented through a fiberglass or steel wool filter system for minimizing PM₁₀ emissions. See Section V.F of this document for information on the BACT analysis for storage tanks.

Monitoring, recordkeeping, and reporting conditions include the requirement to conduct and maintain records of daily opacity observations. EPA Reference Method 9 is specified for performing opacity measurements on the asphalt tank exhaust. Additionally, for the purpose of BACT, the Permittee must monitor tank exhaust gas temperature at the inlet to the particulate filter weekly and maintain records of each periodic reading.

2. VOC and HAP Provisions

Based on the low vapor pressure of asphalt (approximately 0.9 mmHg, or 0.12 kPa at 325 °F), the asphalt storage tank qualifies as a Group 2 storage vessel for the purpose of the refinery NESHAP (40 CFR 63 subpart CC).⁸ As such, the only NESHAP requirements contained in the proposed permit are: 1) the Permittee shall not cause or allow liquid with a true vapor pressure of 3.5 kPa or greater to be stored in the asphalt tank, and 2) readily accessible records showing the dimensions and capacity of the asphalt tank must be maintained.

For the purpose of VOC BACT, the Permittee must maintain records of the liquids stored in the asphalt tank, the period of storage, and the maximum true vapor pressure of such liquids during the respective storage period.

⁸ Vapor pressure data from “Emission Factor Documentation for AP-42 Section 11.1: Hot Mix Asphalt Production.” Final Report. December 2000. EPA OAQPS. Pg. 4-83.

T. Truck and Rail Car Loading Racks (Attachment “B” Section XXI)

1. VOC and HAP Provisions

The proposed permit includes separate and distinct requirements for gasoline product loading racks, distillate product loading racks, and LPG product loading racks. The requirements for all loading racks reflect BACT for VOC emissions; the requirements for gasoline product loading racks also reflect applicable provisions of the petroleum refinery NESHAP [40 CFR 63, subpart CC, § 63.650] for HAP emissions.

Each of these regulations includes provisions requiring leak-tight cargo tanks (i.e., tank trucks or rail cars) and the use of either vapor recovery or vapor destruction units. The requirements generally relating to the loading of leak-tight cargo tanks include procedures relating to the three test methods that are required to be conducted in order to certify a cargo tank as leak-tight: the annual certification test, the leak detection test, and the nitrogen pressure decay field test. In addition, the proposed permit includes a requirement for maintaining the gauge pressure inside the cargo tank within a specified range and a requirement for continuous monitoring of system gauge pressure during loading of cargo tanks.

There is a minor discrepancy within and between the cargo tank pressure and vacuum limitations, and associated monitoring requirements, in the various provisions that are applicable under 40 CFR 63 subpart CC. Specifically, under §§ 60.502(h) and (i) of 40 CFR 60 subpart XX, the pressure limitation is “less than 4,500 pascals (450 mm of water).” (These provisions of subpart XX are referenced by § 63.422(a) of 40 CFR 63 subpart R, which in turn is referenced by § 63.650 of 40 CFR 63 subpart CC.) However, these two values are not equivalent, as is implied by the regulatory language (4,500 pascals is equal to 460 mm of water). In 40 CFR 63 subpart R, the U.S. EPA both corrected the mathematical error in 40 CFR 60 subpart XX and changed the preferred set of units for pressure measurements: The pressure testing required by § 63.425(e)(1) of 40 CFR 63 subpart R requires an initial pressure of “460 mm H₂O (18 in. H₂O).” For the sake of both mathematical accuracy and internal consistency, the Department has used its discretion in specifying all pressure limitations and measurements as “460 mm H₂O (18 in. H₂O)” or equivalent.

In addition, the proposed permit terms reflect BACT, which overlaps significantly with the other applicable regulations. BACT for the gasoline product loading racks requires the use of a vapor recovery unit and a thermal oxidizer, in series, to control VOC emissions. The flow rate of VOC in the exhaust from the vapor recovery unit serving the gasoline product loading racks is limited to 7.5 mg per liter of

gasoline loaded and the VOC emission rate from the thermal oxidizer is limited to 1.25 pounds per million gallons loaded. BACT for the distillate product loading racks requires the use of a thermal oxidizer to achieve a VOC emission limit of 22.0 pounds per million gallons loaded. As discussed in detail in Sections IV.C.7 and IV.E.6 herein, the VOC BACT provisions are more stringent than the corresponding VOC emission limits under the NESHAP. The provisions of these regulations that are less stringent than BACT and directly comparable to the BACT emission limits have been streamlined out of the proposed permit, as described in Sections IV.C.7 and IV.E.6 herein.

Monitoring, recordkeeping, and reporting conditions include compliance determination procedures, the MACT standards, and additional specific BACT and CAM monitoring requirements for the thermal oxidizers. Because the gasoline and distillate product loading racks will share common thermal oxidizers (i.e., one oxidizer at the rail car loading area and one at the truck loading area), the proposed permit includes an equation to be used to determine compliance during periods when a thermal oxidizer is controlling emissions from both gasoline and distillate product loading racks. The control device operating parameters that serve as a surrogate for compliance with the VOC emission limits are the thermal oxidizer combustion chamber temperature and exhaust gas volumetric flow rate. Consistent with the requirements of the CAM rule, the proposed permit requires that the Permittee develop a CAM plan, submit this plan for the Director's approval, and comply with the provisions of the plan at all times. The proposed permit requires that a minimum combustion chamber temperature be established during thermal oxidizer during performance testing; that the maximum exhaust gas volumetric flow rate be established, at a level corresponding to a minimum combustion chamber residence time of at least 0.75 seconds, by engineering calculations; that the exhaust gas flow rate be maintained at or below the specified maximum level continuously, based on a 15-minute averaging period; and that the temperature be maintained at or above the minimum level continuously, based on a 15-minute averaging period. The proposed permit also requires annual inspections of the thermal oxidizer burners and the combustion chamber monitoring system.

2. Thermal Oxidizer Operational Limitations

The Permittee is restricted to using RFG and natural gas in the thermal oxidizers, consistent with the information provided in the permit application. This restriction is necessary to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department.

The proposed permit does not include any enforceable limitation on

the heat input to the loading rack thermal oxidizers. The sole function of the thermal oxidizers is to control emissions of VOC and organic HAPs; the Permittee has no economic incentive to operate these devices at heat input rates higher than necessary to achieve adequate control efficiency. Heat input limits would generally provide disincentive to the Permittee to operate the thermal oxidizers at higher control efficiencies. The emissions of VOC and organic HAP due to insufficient temperature in the thermal oxidizers are substantial; the emissions of combustion-generated pollutants are relatively small. The Department evaluated whether heat input limits are appropriate and determined that the only possible benefit would be improved tracking of PM₁₀ emissions. (Tracking the emissions of other combustion-generated pollutants would be unaffected. Emissions of SO₂ and NO_x are subject to continuous monitoring, and emissions of VOC and CO are inversely related to the thermal oxidizer heat input rate.) The Department concluded that this benefit is significantly outweighed by the potentially greater adverse environmental impacts that would result. Also, it is unlikely that the heat input to either thermal oxidizer will exceed the 12.3 MMBtu/hr rate that was indicated in the permit application. This value is based on an engineering design evaluation of the heat requirements for maintaining the required thermal oxidizer combustion chamber temperature, assuming the maximum gas flow from loading operations. This is a conservative method of estimating required heat input rate to the thermal oxidizer.

3. Thermal Oxidizer SO₂ Emissions

The thermal oxidizers are subject to NSPS (40 CFR 60 subpart J) and BACT requirements for SO₂ emissions. The proposed permit conditions, including emission limits/standards, monitoring, recordkeeping, reporting, and testing requirements, are consistent with those contained in other sections of the proposed permit involving RFG combustion units. The exhaust gases displaced from cargo tanks being loaded are considered to be fuel gas under subpart J, but are not considered to be RFG for the purposes of the SO₂ BACT provisions. See Sections V.B.2 and VI.A of this document for a more detailed discussion of SO₂ BACT and proposed permit conditions for RFG combustion sources.

4. Equipment in VOC and Organic HAP Service

The piping components associated with the Truck and Rail Car Loading Racks may include equipment in VOC and organic HAP service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment "B" of the proposed permit and are referenced in Condition XXI.B.6 of Attachment "B" of the proposed permit. These requirements are discussed in Section VI.X herein.

U. Benzene Waste Operation (Attachment “B” Section XXII)

This section of the proposed permit contains the facility-wide requirements under the Benzene Waste NESHAP (40 CFR 61 subpart FF), as discussed in Section IV.C.2 herein. The provisions of subpart FF are included in the proposed permit, generally without modification, except that requirements and compliance options not pertinent to the proposed refinery have been streamlined from the proposed permit. For example, subpart FF includes extensive requirements for surface impoundments, but the Permittee has not requested permission to construct any surface impoundments. Therefore, the proposed permit includes a prohibition on the use of a surface impoundment for storage and treatment of benzene-containing waste, and the subpart FF requirements for surface impoundments have been omitted from the proposed permit.

The Benzene Waste NESHAP requirements are included in a separate section of the proposed permit only for administrative convenience. The specific provisions in Section XXII of Attachment “B” of the proposed permit are expected to apply primarily to the emission units in the Wastewater Treatment Plant; indeed, as required by Condition XXIII.B.1.a in Attachment “B” of the proposed permit, the Permittee must comply with the provisions of Section XXII of Attachment “B” of the proposed permit for all wastewater, regardless of the benzene concentration threshold specified in subpart FF. This control strategy was proposed by the Permittee as BACT. Therefore, the less stringent requirements under subpart FF, for facilities with relatively low benzene waste quantities, have been omitted from the proposed permit.

1. Wastewater Collection System (Drains)

The proposed permit requires that each drain system be equipped with leak-free covers on all openings. The proposed permit also requires that each junction box be equipped with either water seal controls or a plug, routed to the Wastewater Treatment Plant Thermal Oxidizer, or routed to a dedicated dual carbon canister system. Compliance with these equipment design and work practice requirements is required to be demonstrated by performing and maintaining records of inspections. In addition, if the Wastewater Treatment Plant Thermal Oxidizer is used, the Permittee is required to monitor and record any vent stream flow that is bypassed or diverted from the control device, and if a dedicated dual carbon canister system is used, the Permittee is required to perform continuous monitoring of the exhaust stream for breakthrough.

2. Equalization Tank

The proposed permit requires that the Equalization Tank be equipped with a fixed roof and leak-free covers on all openings. Compliance with these equipment design and work practice requirements is

required to be demonstrated by performing and maintaining records of inspections. The proposed permit also requires that the Equalization Tank be equipped with a closed-vent system, with the vent stream routed to the Wastewater Treatment Plant Thermal Oxidizer, and the Permittee is required to monitor and record any vent stream flow that is bypassed or diverted from the control device.

3. Oil-Water Separator (API Separator)

The proposed permit requires that the API Separator be equipped with a fixed roof and leak-free covers on all openings. Compliance with these equipment design and work practice requirements is required to be demonstrated by performing and maintaining records of inspections. The proposed permit also requires that the API Separator be equipped with a closed-vent system, with the vent stream routed to the Wastewater Treatment Plant Thermal Oxidizer, and the Permittee is required to monitor and record any vent stream flow that is bypassed or diverted from the control device.

4. Dissolved Air Flotation Unit

The proposed permit requires that the Dissolved Air Flotation Unit be equipped with a fixed roof and leak-free covers on all openings. Compliance with these equipment design and work practice requirements is required to be demonstrated by performing and maintaining records of inspections. The proposed permit also requires that the Dissolved Air Flotation Unit be equipped with a closed-vent system, with the vent stream routed to the Wastewater Treatment Plant Thermal Oxidizer, and the Permittee is required to monitor and record any vent stream flow that is bypassed or diverted from the control device.

5. Biotreater

The proposed permit requires that the Biotreater be equipped with a fixed roof and leak-free covers on all openings. Compliance with these equipment design and work practice requirements is required to be demonstrated by performing and maintaining records of inspections. The proposed permit also requires that the Biotreater be equipped with a closed-vent system, with the vent stream routed to the Wastewater Treatment Plant Thermal Oxidizer, and the Permittee is required to monitor and record any vent stream flow that is bypassed or diverted from the control device.

6. Wastewater Treatment Processes, Collectively

The proposed permit requires that the waste treatment processes, collectively, remove benzene from waste by 99 percent, on a mass basis, or to an effluent concentration less than 10 parts per million by

weight (ppmw). Compliance with this requirement is required to be demonstrated either through performing engineering calculations or by measuring benzene quantity in waste before and after (i.e., upstream and downstream of) treatment processes.

The Department recognizes that Condition XXII.B.7.a(3) of the proposed permit, which implements 40 CFR 61.348(a)(3), is potentially confusing. This condition does not proscribe dilution; rather, it proscribes dilution as a means to avoid complying with Conditions XXII.B.2 through XXII.B.6. For example, if a process wastewater stream that would require control is combined with a storm water stream, the combined stream must be treated in units that comply with Conditions XXII.B.2 through XXII.B.6, even if the benzene concentration of the resulting (combined) stream is less than 10 ppmw. The following discussion from the preamble to the March 7, 1990, Federal Register notice (55 FR 8292), announcing promulgation of 40 CFR 61 subpart FF, clarifies that this is the intent of the regulatory provision:

“d. Dilution

“To avoid situations where an owner or operator would dilute or mix waste streams to reduce the benzene concentration below the 10 ppmw cutoff level, the proposed standards included an equation for calculating a concentration limit that must be met when multiple waste streams are combined before treatment. Several commenters stated that the equation is unwieldy and unusable in many situations because of the large number of waste streams that must be considered and the many different ways in which waste streams are combined for transfer or treatment. The EPA agrees that using the dilution equation could be difficult in many situations and has deleted it from the final rule. The final rule allows the combination of individual waste streams to facilitate treatment in a centralized treatment process unit but prohibits the use of dilution or mixing of waste streams for the sole purpose of reducing the benzene concentration.

“While the final rule allows the combination of waste streams for the purpose of centralized treatment, EPA recognizes that this allowance could result in emissions and risks higher than intended in certain cases when many large volume waste streams that contain levels of benzene above and below 10 ppmw are mixed. This situation could occur if an owner or operator chooses to reduce the benzene content of process wastewater streams through treatment that occurs in a facility's wastewater treatment system rather than segregate streams with greater than 10 ppmw benzene for separate treatment. The wastewater treatment system at some facilities, such as at

petroleum refineries, manages large quantities of wastewater made up of a mixture of waste streams having benzene concentrations above and below 10 ppmw. The mixed stream may go through several management steps leading to a biological treatment unit. Due to the large volume of wastes handled, benzene emissions could be substantial even though the benzene concentration in the mixed waste is below 10 ppmw. The dilution equation in the proposed rule would have required an appropriate level of control in these situations by establishing a treatment limit below 10 ppmw for the mixed stream. With the dilution equation deleted in the final rule, some other provision is needed to ensure the streams are treated to an appropriate level. Therefore, a provision has been added to the final rule that applies specifically to those situations where an owner or operator chooses to use an existing wastewater treatment system to meet the treatment requirements of the rule. In these situations, the final rule requires the facility to apply controls to all wastewater treatment units up to the point where the benzene concentration is below 10 ppmw and one of the following occurs: (1) The total annual quantity of benzene in the process wastewater for the facility is reduced below 1 megagram; or (2) the waste has reached the biological treatment unit. Biological treatment units would need to be controlled only if the benzene concentration of the waste entering the unit is 10 ppmw or greater. These units routinely remove up to 80 percent of the organics in dilute waste streams and thus would not be required to meet the 1 megagram per year limit if the concentration entering the unit is less than 10 ppmw.”

The entire preamble discussion is included for completeness, however, references to the “1 megagram per year” compliance option are not applicable to the proposed refinery.

V. Wastewater Treatment Plant (Attachment “B” Section XXIII)

1. Operational Requirements for Wastewater Treatment Vessels

Condition XXIII.B.1.a in Attachment “B” of the proposed permit requires that the Permittee comply with the provisions of Section XXII of Attachment “B” of the proposed permit for all process wastewater, regardless of benzene concentration. The requirements of Section XXII of Attachment “B” of the proposed permit are discussed in Section VI.V herein.

2. Operational Requirements for the Thermal Oxidizer

The Permittee is restricted to using RFG and natural gas in the Wastewater Treatment Plant Thermal Oxidizer, consistent with the

information provided in the permit application. This restriction is necessary to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department.

Other design standards and operational requirements for the Wastewater Treatment Plant vessels and Thermal Oxidizer include the most stringent requirements of 40 CFR 61 subpart FF, and additional, more stringent requirements for the Thermal Oxidizer for the purpose of BACT. Specifically, for the Wastewater Treatment Plant Thermal Oxidizer, VOC BACT emission limitations are design standards and operational requirements including minimum design VOC destruction efficiency (≥ 99.9 percent), minimum combustion chamber temperature (≥ 1600 °F), and maximum exhaust gas volumetric flow rate corresponding to a minimum residence time (≥ 0.75 second).

Monitoring, recordkeeping, and reporting conditions include the compliance determination procedures of subpart FF and additional specific BACT monitoring requirements for the Thermal Oxidizer. The most important compliance requirement for the Thermal Oxidizer is a requirement for a design evaluation and monitoring plan, similar to that required for the Tank Farm Thermal Oxidizer under the MACT regulations. In addition, the Thermal Oxidizer must be equipped with continuous monitoring systems for combustion chamber temperature and exhaust gas volumetric flow rate. Excess emissions for the purpose of BACT are defined as each 5-minute block during which the thermal oxidizer combustion chamber outlet temperature falls below the specified minimum or the exhaust gas volumetric flow rate exceeds the specified maximum. An annual inspection of the thermal oxidizer burner and temperature monitoring system is also required.

The proposed permit does not include any enforceable limitation on the heat input to the Wastewater Treatment Plant Thermal Oxidizer. The sole function of the thermal oxidizer is to control emissions of VOC and organic HAPs; the Permittee has no economic incentive to operate the device at a heat input rate that is higher than necessary to achieve adequate control efficiency. A heat input limit would generally provide disincentive to the Permittee to operate the thermal oxidizer at higher control efficiencies. The emissions of VOC and organic HAP due to insufficient temperature in the thermal oxidizer are substantial; the emissions of combustion-generated pollutants are relatively small. The Department evaluated whether a heat input limit is appropriate and determined that the only possible benefit would be improved tracking of PM₁₀ emissions. (Tracking the emissions of other combustion-generated pollutants would be unaffected. Emissions of SO₂ and NO_x are subject to continuous monitoring, and emissions of VOC and CO are inversely related to the thermal oxidizer heat input rate.) The Department concluded that this benefit is significantly outweighed by the potentially greater adverse

environmental impacts that would result. Also, it is unlikely that the heat input will exceed the 0.334 MMBtu/hr rate that was indicated in the permit application. This value is based on an engineering design evaluation of the heat requirements for maintaining the required thermal oxidizer combustion chamber temperature, assuming a gas flow that reflects the simultaneous maximum rate of displacement from all Wastewater Treatment Plant vessels. This is a conservative method of estimating required heat input rate to the thermal oxidizer.

3. SO₂ Emissions from the Thermal Oxidizer

The Wastewater Treatment Plant Thermal Oxidizer is subject to NSPS (40 CFR 60 subpart J) and BACT requirements for SO₂ emissions. The proposed permit conditions, including emission limits/standards, monitoring, recordkeeping, reporting, and testing requirements, are consistent with those contained in other sections of the proposed permit involving RFG combustion units. See Sections V.B.2 and VI.A of this document for a more detailed discussion of SO₂ BACT and proposed permit conditions for RFG combustion sources. Note that the exhaust gases displaced from wastewater treatment vessels are considered to be RFG both under subpart J and for the purposes of the SO₂ BACT provisions.

4. Spray Dryer Heater

The Wastewater Treatment Plant includes one process heater: the Spray Dryer Heater. This heater is required to use low-NO_x burners to control NO_x emissions. See Sections VI.A.1 through VI.A.6 herein for a discussion of the requirements relating to this process heater.

5. Opacity and PM₁₀ Emissions from the Spray Dryer Baghouse

The opacity and particulate matter emission limits applicable to the Spray Dryer Baghouse under BACT, A.A.C. R18-2-702(B), and A.A.C. R18-2-730(A)(1) are included in the proposed permit. The PM BACT emission limit of 0.005 gr/dscf will be significantly more stringent than the process weight-based limit under A.A.C. R18-2-730(A)(1) during normal operation. However, it is theoretically possible that the latter limit could be more stringent under some operating conditions. For this reason, the PM emission limit under A.A.C. R18-2-730(A)(1) has not been streamlined from the permit.

The compliance demonstration requirements for this emission unit include monitoring of pressure drop; periodic inspections and visible emissions observations; and initial and annual particulate matter emission tests. These compliance demonstration requirements meet the provisions of the applicable state regulations as well as the federal CAM rule. See Section IV.F herein for a detailed discussion of CAM requirements.

6. Equipment in VOC, Organic HAP, and Hydrogen Sulfide Service

The piping components in the Wastewater Treatment Plant may include equipment in VOC, organic HAP, and hydrogen sulfide service. The requirements pertaining to this equipment are consolidated in Section XXIV of Attachment “B” of the proposed permit and are referenced in Condition XXIII.B.4 of Attachment “B” of the proposed permit. These requirements are discussed in Section VI.X herein.

W. Equipment Leaks (Attachment “B” Section XXIV)

1. Organization of Proposed Permit Conditions

The general organization and subsection headings under Section XXIV of Attachment “B” of the proposed permit differ from other sections of the proposed permit to better align with leak detection and repair (LDAR) NESHAP and BACT provisions. Section XXIV.B contains emission limitations, standards, and monitoring provisions including general requirements (XXIV.B.1); equipment category specific VOC and organic HAP equipment leak provisions (XXIV.B.2 through XXIV.B.15); H₂S equipment leak provisions (XXIV.B.16); and restrictions designed to make enforceable the benzene emission rate from equipment leaks (XXIV.B.17). Section XXIV.C contains recordkeeping and reporting requirements, and Sections XXIV.D and XXIV.E contain source testing and permit shield provisions, respectively.

2. General Equipment Leak Provisions: VOC, Organic HAP, and H₂S Emissions

Section XXIV.B.1 of Attachment “B” of the proposed permit contains general equipment leak provisions corresponding with the NESHAP provisions in 40 CFR 63.648 (subpart H § 63.161 and 63.162 by reference) and BACT for VOC and H₂S emissions. These conditions include definitions of affected equipment, general equipment identification requirements, specifically excluded equipment (e.g., equipment in vacuum service), identification procedures for equipment leaks, general task completion and equipment repair timing specifications, and general BACT equipment specifications. For the purpose of BACT, many of the NESHAP conditions were modified to apply to equipment in VOC or organic HAP service. Equipment in H₂S service was defined as all equipment that contains or contacts a fluid that is at least 2 percent by weight H₂S (see Section V.I.2 herein for a complete discussion of BACT for H₂S emissions from equipment leaks). All proposed BACT permit conditions were identified by regulatory citation [A.A.C. R18-2-406(A)(4)].

3. Equipment-Specific Provisions: VOC and Organic HAP Emissions

Refinery-wide equipment in organic HAP service are subject to the new source requirements of the petroleum refinery NESHAP, 40 CFR 63 subpart CC § 63.648. In accordance with 63.648(a), new sources must comply with the HON equipment leak provisions of 40 CFR 63 subpart H. Sections XXIV.B.2 through XXIV.B.15 of Attachment “B” of the proposed permit contain equipment-specific VOC and organic HAP equipment leak provisions organized consistently with 40 CFR 63 subpart H (§§ 63.163 through 63.179) as follows:

XXIV.B.2	Pumps in Light Liquid Service
XXIV.B.3	Compressors
XXIV.B.4	Pressure Relief Devices in Gas/Vapor Service
XXIV.B.5	Sampling Connection Systems
XXIV.B.6	Open-ended Valves or Lines
XXIV.B.7	Valves in Gas/Vapor Service and in Light Liquid Service
XXIV.B.8	Pumps, Valves, Connectors, and Agitators in Heavy Liquid Service; Instrumentation Systems; and Pressure Relief Devices in Liquid Service
XXIV.B.9	Surge Control Vessels and Bottoms Receivers
XXIV.B.10	Delay of Repair
XXIV.B.11	Closed-vent Systems and Control Devices
XXIV.B.12	Connectors in Gas/Vapor Service and in Light Liquid Service
XXIV.B.13	Quality Improvement Program for Valves
XXIV.B.14	Quality Improvement Program for Pumps
XXIV.B.15	Alternative Means of Emission Limitation

The NESHAP includes requirements for categories of equipment that will not be present at the proposed refinery. These requirements, for agitators in gas/vapor service and in light liquid service (pursuant to § 63.173) and for batch processes (pursuant to § 63.178) are not included in the proposed permit.

The proposed permit conditions in Sections XXIV.B.2 through XXIV.B.15 of Attachment “B” of the proposed permit are consistent with the provisions of §§ 63.163 - 63.179 of subpart H. As discussed in Section V.I of this document, the HON equipment leak provisions were deemed representative of baseline BACT for VOC emissions from equipment leaks. Because the requirements reflecting BACT are somewhat more stringent, streamlining of the applicable NESHAP provisions is incorporated in the proposed permit as follows:

- Extending the applicability of the NESHAP provision to apply to equipment either in VOC service or organic HAP service;
- Revising the equipment leak definition to reflect the BACT concentration threshold of 100 ppmv for valves and connectors

- in gas/vapor and light liquid service;
- Revising the equipment leak definition to reflect the BACT concentration threshold of 500 ppmv for all other equipment categories;
- Revising the required deadlines for the first attempt at repair (from 5 days down to 24 hours) and for successful repair (from 15 days down to 7 days) for valves in gas/vapor service or light liquid service, connectors in gas/vapor service or light liquid service, pumps in light liquid service, and compressors;
- Eliminating the provisions for designating pumps in light liquid service as “unsafe to monitor” and for monitoring these pumps with less frequency than other pumps;
- Eliminating the provisions providing for reduced monitoring frequency for valves in gas/vapor service or light liquid service;
- Eliminating the quality improvement program provisions for pumps in light liquid service, as the applicability threshold for this program (in terms of percent leaking components) is above the allowable level representing BACT; and
- Eliminating the provisions for increased monitoring frequency and the quality improvement program provisions for valves in gas/vapor service or light liquid service, as the applicability thresholds for these provisions (in terms of percent leaking components) are above the allowable level representing BACT.

Additional specific BACT conditions, including equipment technology requirements and specifications as documented in Section V.I herein, are also incorporated. Section V.I of this document presents a complete discussion of BACT selection for equipment leaks and supporting analyses. Each proposed permit condition is referenced with corresponding regulatory citations (i.e., NESHAP and/or BACT).

4. Equipment Leak Provisions for H₂S Emissions

Section XXIV.B.16 of Attachment “B” of the proposed permit contains emission limitations/standards and monitoring requirements for H₂S emissions from equipment leaks. These requirements exclusively represent BACT, and are discussed in detail in Section V.I.2 of this document.

5. Equipment Leak Provisions for Benzene Emissions

Section XXIV.B.17 of Attachment “B” of the proposed permit contains limitations on the number of components in organic HAP service. These provisions are included in the proposed permit in order to make enforceable the benzene emission rates that were included in the AAAQG modeling analysis, discussed in Section VII.A.3.e herein.

6. Recordkeeping and Reporting Requirements

Section XXIV.C of Attachment “B” of the proposed permit contains recordkeeping and reporting requirements for equipment leaks. In accordance with 40 CFR 63.654(d), HON subpart H recordkeeping requirements (§ 63.181) and reporting requirements (§ 63.182) must be met with certain exceptions. These requirements are incorporated in the proposed permit along with other applicable requirements under § 63.654. Modifications to proposed NESHAP-based permit conditions were made to incorporate BACT requirements.

7. Testing Requirements

The equipment leak test methods and procedures required by the NESHAP (40 CFR 63.180) are incorporated in Section XXIV.D.1 of Attachment “B” of the proposed permit for the purpose of both MACT and BACT compliance. The requirements specify EPA Reference Method 21 of 40 CFR part 60 for monitoring VOC and organic HAP emissions from equipment leaks.

X. Emergency Flares (Attachment “B” Section XXV)

1. Emergency Usage

The proposed permit prohibits the use of the two emergency flares to combust any gases other than natural gas, as pilot gas and purge gas, and process upset gases generated during malfunctions. These proposed permit conditions reflect and make enforceable the Permittee’s commitment to operate the emergency flares only to control emissions during periods of upset and malfunction.

2. Equipment Design and Work Practice Requirements

The proposed permit includes design requirements related to exit velocity and flame detection, to ensure that the flare is continuously available for controlling emissions, and smokeless operation, to ensure that emission control is maximized during periods of upset and malfunction. Specifically, the proposed permit requires a design incorporating steam assist; limits exit velocity to a maximum of 60 ft/sec; requires that natural gas purge be employed so that the net heating value of the gas being combusted is at least 300 Btu/scf; requires the continuous presence of a pilot flame, with monitoring conducted using a thermocouple or equivalent device; and requires operation with no visible emissions, with visible emissions observations conducted for each flare event. These proposed permit conditions are based largely on the parallel requirements set forth in the NSPS regulations (40 CFR 60.18) and the NESHAP regulations (40 CFR 63.11).

3. Testing Requirements

In addition, the proposed permit includes requirements for a flare operation, monitoring, and maintenance plan that will ensure collection of representative emission data during flare events. These data can be utilized by the Permittee in implementing design and work practice changes, and will be utilized by the Department for the purposes of determining appropriate enforcement action for flare events.

Y. Steam Boilers (Attachment “B” Section XXVI)

1. Fuel Use

The Permittee is restricted to using natural gas in the steam boilers, consistent with the information provided in the permit application, and heat input is limited to the maximum rates indicated in the permit application. These restrictions are needed to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department.

2. NO_x Emissions

Each of the steam boilers is required to use low-NO_x burners and flue gas recirculation to control NO_x emissions. Each is subject to a NO_x emission limit of 0.0125 lb/MMBtu heat input (HHV), based on a rolling three-hour average, representing BACT. In addition, for each steam boiler, the proposed permit includes the NSPS emission limit of 0.20 lb/MMBtu, based on a rolling 30-day average. Although the NSPS limit is substantially less stringent than the BACT limit during normal operations, the NSPS limit does not provide an exception for periods of startup, shutdown, or malfunction. Thus, the NSPS limit has the potential to be more stringent during some periods, and for this reason it has not been streamlined from the permit. Compliance with the NO_x emission limits is required to be demonstrated using CEMS. Each CEMS is required to meet the performance and quality assurance requirements of 40 CFR part 60, appendices B and F.

3. CO Emissions

Each of the steam boilers is subject to a CO emission limit representing BACT. Compliance with these emission limits is required to be demonstrated using CEMS. Each CEMS is required to meet the performance and quality assurance requirements of 40 CFR part 60, appendices B and F.

Z. Cooling Tower (Attachment “B” Section XXVII)

1. Circulating Water Flow Rate

Circulating water flow rate is limited to the maximum rate indicated in the permit application. This restriction is needed to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department.

2. Opacity of Visible Emissions

The Cooling Tower is subject to A.A.C. R18-2-702(B) for visible emissions. The applicable 20 percent opacity limit was incorporated in the proposed permit. However, because any particulate matter that is emitted from the cooling tower will occur as drift, which by definition is uncombined water, valid determination of opacity using EPA Reference Method 9 is not expected to be feasible. In addition, the particulate matter emissions from the cooling tower are expected to be very low in relation to the exhaust gas volumetric flow. For these reasons, compliance with the applicable opacity standard under this regulation is presumed under all operating conditions, and no monitoring or testing is required.

3. Particulate Matter Emissions

The proposed permit includes a limit on the particulate matter emission rate representing the modeled emission rate and a requirement for high-efficiency drift eliminators representing BACT. Compliance with the particulate matter emission rate is required to be demonstrated initially through testing and on a continuing basis through calculations using circulating water flow rate, drift eliminator design efficiency, and solids loading in the circulating water as determined through monthly measurements.

4. Heat Exchange System Operational Requirements

The proposed permit includes equipment design and work practice requirements representing BACT for VOC emissions. (See Section V.L.2 herein for a detailed discussion of the VOC BACT determination for the cooling tower.) Compliance with these operational requirements is to be demonstrated through recordkeeping and reporting requirements.

AA. Internal Combustion Engines (Attachment “B” Section XXVIII)

1. Fuel Specification and Fuel Consumption Limitations

Fuel consumption in each internal combustion engine is restricted to No. 2 distillate fuel oil, and fuel consumption during non-emergency situations is limited to the maximum rates indicated in the permit application. (Heat input capacities specified in the permit application were converted to fuel consumption rates using a heating value of

140,000 British Thermal Unit (Btu) per gallon for No. 2 diesel fuel.) These restrictions are needed to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department.

In addition, the sulfur content of the No. 2 distillate fuel oil burned in each of the internal combustion engines is limited to a maximum of 15 ppmw, representing BACT for SO₂ emissions. Compliance with these proposed permit terms is required to be demonstrated through recordkeeping. On each day that a particular engine is operated, the Permittee is required to create and maintain records of the quantity and type of fuel combusted, as well as the sulfur content and the method by which the sulfur content was determined.

2. NO_x, CO, and PM Emissions

The proposed permit includes a requirement that each internal combustion engine be guaranteed by the engine manufacturer to achieve NO_x, CO, and PM emissions equal to or less than the levels determined to represent BACT. The proposed permit also requires that each engine be operated and maintained in accordance with the engine manufacturer's instructions and recommendations. Compliance with these requirements is required to be demonstrated through recordkeeping. The Permittee is required to maintain, for the life of each engine, records of the manufacturer's emission performance guarantee for that engine. The Permittee is also required to maintain records of all maintenance performed on each engine.

3. Visible Emissions

The Internal Combustion Engines are subject to A.A.C. R18-2-719(E) for visible emissions. The applicable 40% opacity limit was incorporated in the proposed permit for each internal combustion engine. Compliance with this limitation is required to be demonstrated through monitoring and recordkeeping. The Permittee is required to perform visible emissions observations, using EPA Reference Method 9, for at least six minutes on each day that a particular engine is operated (other than emergency operations). The Permittee is also required to maintain records of all visible emissions observations. Finally, the proposed permit includes a prohibition on routine (i.e., non-emergency) operation of any internal combustion engine at any time when a visible emissions observation, using EPA Reference Method 9, cannot be performed. This prohibition is not applicable (i.e., operation at any time of day is allowed) on any day on which the requirement for a visible emissions observation has been met for the particular engine.

BB. Mobile Sources and Fugitive Dust Sources (Attachment "B" Section

XXIX)

1. Visible Emissions

All nonpoint emission sources are subject to a 40 percent opacity limitation for visible emissions, based on a six-minute average, under A.A.C. R18-2-612. Nonpoint emission sources subject to this regulation include, but are not limited to, open areas, dry washes, riverbeds, roadways, streets, parking lots, storage piles, and material handling operations. The applicable 40 percent opacity limit for nonpoint emission sources was incorporated into the proposed permit.

Mobile sources, excluding motor vehicles and agricultural vehicles, are subject to a 40 percent opacity limitation for visible emissions under A.A.C. R18-2-801, -802, and -804. Compliance with these requirements is based on an observation period of ten consecutive seconds. Mobile sources subject to these regulations include, but are not limited to, offroad machinery and roadway cleaning machinery. The applicable 40 percent opacity limits were incorporated into the proposed permit for visible emissions from these categories of sources.

2. Work Practices

The proposed permit requires that the Permittee prepare, submit, and adhere to a dust control plan; that the dust control plan include and address specific work practices; and that the Permittee pave all roadways and vehicle parking lots. These requirements implement the provisions of A.A.C. R18-2-604, -605, -606, and -607 and the BACT requirements.

VII. AIR QUALITY IMPACT ANALYSIS

A. Ambient Air Quality Impacts Analysis

1. General

The site of the proposed refinery is located in an area that has been designated as attainment or unclassifiable for all criteria pollutants. Therefore, the relevant ambient air quality impact analyses requirements are found in A.A.C. R18-2-406(A)(5) and R18-2-407. The air quality analyses must demonstrate that the project's proposed significant emission increases will not cause or contribute to an exceedance of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. (There are primary and secondary NAAQS, and there are separate Class I and Class II PSD increments.) It must also demonstrate the project's proposed significant emission increases will not contribute to an increase in ambient concentrations for a pollutant by an amount in excess of the significance level in any area in which NAAQS for that pollutant are being violated. The PSD pollutants that are proposed to be emitted in significant quantities include NO_x, CO, SO₂, VOC, and PM₁₀.

The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere. For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the background ambient concentrations, the estimated ambient impacts of existing sources of air pollution, and the estimated ambient impacts of the applicant's proposed emissions. A PSD increment, on the other hand, is the maximum increase in ambient concentration that is allowed to occur above a baseline concentration for a pollutant. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. PSD increments have been established for Class II areas, and at lower acceptable levels for Class I areas such as national parks (to further limit air quality degradation in Class I areas).

Additional air quality analyses required under A.A.C. R18-2-407 include an analysis of the impairment to visibility, soils, and vegetation, and an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the new major source.

The nearest Class I area to the proposed project site is Joshua Tree National Park, located 191 km away. Because no adverse effects were predicted for the facility when it was proposed at the Mobile site, when the nearest Class I area was only 88 km away from the facility, the Department has concluded that there will be no adverse effects at 191 km away from the Mohawk site. Consequently, the Department has

largely relied on the detailed Class I area impact analysis that was previously performed for the Mobile site, and a detailed impact analysis for Class I areas was not performed for the Mohawk site.

The Muggin Mountains Wilderness area lies between 32 and 40 km northwest of the project site. While this area is classified as Class II, and is not subject to the special protections afforded Class I areas under A.A.C. R18-2-406(A)(5) and R18-2-407, it is considered by the Department to be a “sensitive” Class II area. Therefore, the Department requested, and the applicant performed, a visibility analysis for this sensitive Class II area.

The “ADEQ Air Quality Division Modeling Guidelines,” June 22, 1998 (hereinafter, “ADEQ MG”), presents policy statements and guidance on many air quality analysis issues, including the authority and application of the Arizona Ambient Air Quality Guidelines (AAAQG). Section 1.3 of Appendix B of the ADEQ MG describes the Department’s current HAP/AAAQG program policy, and outlines the legal authority and procedural requirements. In accordance with this Department policy, the Permittee has submitted an AAAQG modeling analysis as part of the PSD permit application.

Finally, as described in A.A.C. R18-2-730(H), “No person shall allow hydrogen sulfide to be emitted from any location in such manner and amount that the concentration of such emissions into the ambient air at any occupied place beyond the premises on which the source is located exceeds 0.03 parts per million by volume for any averaging period of 30 minutes or more”. The ambient air quality impact analysis performed by the applicant includes an assessment of the predicted hydrogen sulfide impacts from the proposed facility in the results of the AAAQG analysis. The 1-hour impact can be converted to units of ppm and compared to the 0.03 ppm standard.

2. Modeling Methodology

a. Department and U.S. EPA Modeling Analysis Guidance

The Department’s technical requirements and guidance for air quality analyses are described in the ADEQ MG. Additionally, the U.S. EPA’s guidance for performing PSD air quality analyses is set forth in the “Guideline on Air Quality Models” (GAQM), codified in 40 CFR Part 51 Appendix W, and in Chapter C of the October 1990 New Source Review Workshop Manual. These guidance documents were utilized to assess the completeness and accuracy of the Arizona Clean Fuels air quality analyses.

b. Arizona Clean Fuels Dispersion Modeling Protocol

For a PSD permit application, the Department requires the submittal and subsequent approval of a dispersion modeling protocol before a dispersion modeling analysis is accepted. Development of the modeling protocol document guides the applicant in fulfilling all necessary requirements. A recommended protocol format, including suggested content, is described in the ADEQ MG. The Department reviews the protocol and provides comments to the applicant on any deficiencies. After approval of the modeling protocol, the Department will then accept the modeling report. All Class I air quality permit applications should include a formal modeling report summarizing the results of the modeling. Again, the ADEQ MG present a recommended format and suggested content for the modeling report.

The Department received the modeling protocol for the Arizona Clean Fuels project, prepared by URS Corporation, in February 2004. The protocol was reviewed and, in general, it conformed to ADEQ MG and U.S. EPA requirements.

The following sections summarize the procedures and data used in the analysis, and present significant Department comments on the protocol and evaluation comments on the final modeling report.

c. Computer Models Used

The refined model proposed for the air quality analyses is the Industrial Source Complex 3 Short Term Model (ISCST3, version 02035). This model has been approved by the Department for use in the load screening, NAAQS, PSD increment, and AAAQG analyses.

For modeling the Class II visibility impacts within 50 km of the facility, the VISCREEN model was used.

d. Receptor Grid

For the purposes of demonstrating compliance with the PSD increment, NAAQS, and the AAAQGs, a receptor grid was created with sufficient density to determine the maximum model-predicted impact within the surrounding ambient air. Receptor elevations were derived from the United States Geological Service (USGS) 7.5 minute and 1-degree (DEM) data using the AERMAP program.

The Permittee had used the property boundary to represent the process area boundary, as appropriate. While the applicant used 50 meter spacing of receptors along the process boundary

and 100 meter spacing within 500 meters of the property boundary, the Department used 25 meter spacing of receptors during its review to ensure compliance with all applicable standards, increments, and AAAQGs.

e. Meteorological Data

Five years of surface and upper air data from the nearest National Weather Service airport observation station were used in the dispersion modeling analysis. Five years of surface meteorology observed between 1998 and 2002 from the Yuma International Airport were used in conjunction with concurrent upper air observations from Tucson, AZ.

The US EPA mixing height program was used to calculate twice daily mixing heights based on parameters from the Yuma Surface data and Tucson upper air data.

f. Downwash and Good Engineering Practice (GEP)

Because of the effect of building downwash, BPIP was used to calculate the building downwash parameters for input into ISCST3. All of the facility stacks are subject to downwash. The building locations and GEP analysis were independently confirmed. All but two stacks are below the maximum 65 meter allowable GEP height. The two flares (EP13 and EP21) were originally modeled with a height of 100 meters. In the revised confirmatory modeling performed by the Department, the flare heights were adjusted to 65 meters.

During the review of the modeling files, the location of the cooling tower structure was offset from the cooling tower discharge points by approximately 40 meters to the east of where the first emission point is located. Additionally, the height of the cooling tower was modeled at 50.82 meters tall, whereas the point source emission was modeled at 18.30 meters. BPIP was revised to align the tower structure with the emission points. The height of the cooling cells was reset to 1 meter below the release height of the point sources and the revised building parameters were used in the verification of the modeling results. This change did not significantly alter the results.

g. Background Concentrations

The background concentration values presented in Table VII-1 were approved by the Department and used in the modeling analysis. The CO, and O₃ values were based upon the Surprise monitoring station from observations taken during 2001-2002

data. The background SO₂ concentrations are based upon observations at the Phoenix Roosevelt Street station, using the 200-2002 data. The NO₂ value was based upon observations at the Palo Verde station during 2000-2002.

Background SO₂ concentrations were selected based upon the following information. In Arizona, the principal sources of sulfur dioxide emissions has been primary copper smelters and coal-fired power plants. In addition to these sources, most fuels (e.g., gasoline) contain trace quantities of sulfur, and their combustion releases both gaseous sulfur dioxide (SO₂) and particulate sulfate (SO₄). A recent sulfate inventory for Phoenix shows 32 percent of SO₂ emissions come from point sources, 26 percent from area sources, 23 percent from off-road vehicles and equipment, and 19 percent from on-road motor vehicles. Sulfur dioxide is removed from the atmosphere through dry deposition on plants and its conversion to sulfuric acid and eventually to sulfate. Sulfur dioxide has extremely low background levels, with elevated concentrations found downwind of large point sources. Concentrations in urban areas are low and are homogeneously distributed.

Upon reviewing existing ambient monitoring data to represent background SO₂ concentrations, all the sites were determined to be influenced by either copper smelters or coal fired power plants, with the exception of the three urban sites: Central Phoenix, South Scottsdale, and Craycroft (Tucson). Vehicular traffic accounts for most of the gaseous SO₂ being measured in the cities. The Department has taken the “Central Phoenix,” aka “Roosevelt Street” 2000-2002 values as adequately conservative. Obviously, lower concentrations could be utilized from the other two urban sites.

The background PM₁₀ values were based upon the average concentrations observed from the Yuma/Ajo monitoring stations between 2000-2002.

Table VII-1. Ambient Background Monitored Air Quality

Pollutant	Averaging Period	Background Concentration	NAAQS (µg/m³)
CO	1-hour	2807 µg/m ³	40,000
	8-hour	1260 µg/m ³	10,000
SO ₂	3-hour	47.2 µg/m ³	1,300
	24-hour	27.1 µg/m ³	365
	Annual	7.86 µg/m ³	80
NO ₂	Annual	9.41 µg/m ³	100
O ₃	1-hour	0.090 ppm	0.12 ppm

	8-hour	0.077 ppm	0.08 ppm
PM ₁₀	24-hour	98.2 µg/m ³	150
	Annual	30.3 µg/m ³	50

h. Source Data for the Project

The emission rates and stack parameters used in the modeling analysis are presented in Table VII-2 for point sources, Table VII-3 for area sources, and Table VII-4 for volume sources.

Tables VII-2, VII-3, and VII-4 present the emissions data and stack parameters that represent the operating loads with maximum ambient impacts (i.e., the worst-case load scenarios). Refer to the Permittee's modeling report for stack parameters and emission rates for each operating load.

i. NAAQS and PSD Increment Inventory

The maximum radius of impact (ROI) of the proposed facility was determined to be 7.5 km. Data for other sources within 58 km of the proposed site (i.e., the 7.5 km ROI plus 50 km, rounded) were compiled for the NAAQS cumulative inventory. The emissions, stack parameters, and locations for these sources are presented in Appendix B of the Permittee's modeling report. Approximately 19 other point sources and 30 area sources representing emissions from nearby interstate highways were included in the cumulative modeling inventory. The modeling protocol describes the procedures used to select sources, and to estimate stack parameters when they were not available. The inventory was developed by the Permittee in consultation with the Department and Yuma County.

Although Section 4.3 of the Permittee's modeling report stated that certain sources were excluded from the increment inventory based on the minimal emission rates that allowed elimination of the source based on the "20D" criteria," this was not actually the case. For reference, the "20D" criteria is a screening method that was developed by the State of North Carolina which allows applicants to eliminate off-site sources whose emissions (expressed in tons per year) are less than 20 times the distance from the proposed project source (expressed in km). For example, a source located 20 km away from the project with emissions less than one ton per year of the pollutant in question would not have to be included in the PSD increment consumption analysis. The rationale is that these sources are too small to have a significant impact at the distance. Again, however, this procedure was not actually utilized for this project.

The same source inventory used for the NAAQS analysis was also used for the Class II area PSD increment analysis. This is a conservative assumption because some of the NAAQS sources are not PSD increment-consuming sources and because the allowable rather than the actual emission rates were modeled for increment consumption.

Table VII-2. Source Emissions and Stack Parameters for Arizona Clean Fuels Point Sources

Source ID	UTM Easting (m)	UTM Northing (m)	Elevation (m)	NO _x (g/s)	CO (g/s)	SO ₂ (g/s)	PM ₁₀ (g/s)	VOC (g/s)	Stack Ht (m)	Temp (K)	Velocity (m/s)	Diameter (m)
EP1	232232	3623680	102	9.70E-01	2.24E+00	3.28E-01	4.28E-01	2.27E-01	50.3	461	13.6	2.59
EP2	232583	3623700	103	6.93E-01	2.24E+00	3.28E-01	4.16E-01	2.27E-01	50.3	450	14.7	2.13
EP3	232570	3623700	103	8.82E-02	1.13E-01	1.26E-02	2.52E-02	1.26E-02	50.3	589	13.2	0.67
EP4	232477	3623600	102	7.56E-02	1.38E-01	1.26E-02	2.52E-02	1.26E-02	50.3	650	13.8	0.67
EP5	232418	3623610	102	5.67E-01	7.18E-01	1.01E-02	1.39E-01	7.56E-02	50.3	478	13.0	1.52
EP6	232693	3623730	103	9.70E-01	1.42E+00	2.02E-01	2.65E-01	1.39E-01	50.3	450	14.6	1.98
EP7	232817	3623690	103	2.26E+00	7.23E+00	1.05E+00	1.36E+00	7.18E-01	50.3	422	16.7	3.66
EP8	232837	3623620	103	6.55E-01	8.44E-01	3.78E-02	3.91E-01	2.14E-01	50.3	622	14.8	3.20
EP9	232837	3623620	103	6.55E-01	8.44E-01	3.78E-02	3.91E-01	2.14E-01	50.3	622	14.8	3.20
EP10	231952	3623300	103	7.56E-01	1.01E+00	1.51E-01	1.89E-01	1.01E-01	50.3	450	13.4	1.68
EP11	232603	3623660	103	1.03E-01	6.30E-02	N/A	N/A	N/A	61.0	361	8.0	0.23
EP12	232303	3623660	102	7.56E+00	1.06E+00	4.23E+00	1.01E-01	7.56E-02	50.3	1089	9.5	3.66
EP13	231928	3623799	102	7.56E-03	3.91E-02	6.68E-05	N/A	6.30E-03	106.7 ¹	811	5.6	1.22
EP14	231678	3623210	103	N/A	N/A	N/A	1.13E-02	N/A	30.5	200	21.0	0.25
EP15	232883	3624050	103	N/A	N/A	N/A	1.47E-01	N/A	30.5	394	10.6	1.52
EP16	232022	3623290	103	2.90E-01	5.92E-01	3.78E-02	5.04E-01	1.16E-01	15.2	1089	16.17	3.05
EP16r	232022	3623290	103	N/A	N/A	N/A	N/A		15.2	310	3.0	1.00
EP17	232496	3623410	103	1.55E-01	1.31E-01	8.82E-03	1.13E-02	1.75E-01	22.9	533	25.9	1.52
EP18	232877	3623980	103	4.16E-03	3.53E-03	2.52E-04	3.20E-04	1.02E-00	22.9	533	25.9	1.52
EP19	232837	3623850	103	1.01E+00	3.21E+00	4.66E-01	6.05E-01	3.15E-01	50.3	422	16.8	2.96
EP20	232838	3623810	103	8.44E-01	1.12E+00	1.64E-01	2.14E-01	1.13E-01	50.3	422	16.8	1.49
EP21	231714	3623806	102	7.56E-03	3.91E-02	6.68E-05	N/A	6.30E-03	91.4 ¹	811	5.6	1.22
EP22	232838	3623760	103	1.01E-01	6.31E-02	N/A	N/A	N/A	60.96	360.93	8.05	0.23
EP23	232854	3624020	103	1.64E-01	2.27E-01	3.78E-02	3.78E-02	2.52E-02	30.5	644	13.7	1.01
EP24	232089	3623510	102	5.61E-02	1.04E-00	7.69E-02	1.34E-02	1.34E-02	6.1	589	50	0.25
EP25	231847	3623510	102	2.82E-02	5.20E-01	3.78E-02	3.91E-02	6.68E-02	6.1	589	50	0.25

Table VII-2. Source Emissions and Stack Parameters for Arizona Clean Fuels Point Sources

Source ID	UTM Easting (m)	UTM Northing (m)	Elevation (m)	NO _x (g/s)	CO (g/s)	SO ₂ (g/s)	PM ₁₀ (g/s)	VOC (g/s)	Stack Ht (m)	Temp (K)	Velocity (m/s)	Diameter (m)
EP26	232560	3623720	103	2.82E-01	5.20E-01	3.78E-02	3.91E-03	6.68E-02	6.1	589	50	0.25
EP27	231606	3623270	103	1.55E-01	1.31E-01	8.82E-03	1.13E-02	1.75E+00	22.9	533	25.9	1.52
EPCT01	232274	3623760	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT02	232286	3623760	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT03	232298	3623760	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT04	232311	3623760	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT05	232323	3623760	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT06	232274	3623770	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT07	232287	3623770	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT08	232298	3623770	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT09	232312	3623770	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6
EPCT10	232323	3623770	102	N/A	N/A	N/A	2.02E-02	4.23E-02	18.3	311	1.33	8.6

- Notes: 1 - Stack Height modeled at 65 meters.
 2 - Evaluation of emission estimates for these sources resulted in revised pollutant concentrations. The concentrations presented here were input into confirmatory modeling files.
 N/A = Not Applicable

Table VII-3. Source Emissions and Parameters for Arizona Clean Fuels Area Sources

Source ID	UTM Easting (m)	UTM Northing (m)	Release Height (m)	PM₁₀ (g/s)	AAAQG VOC (g/s)	Area Width or Lateral Dimension (m)	Area Length or Vertical Dimension (m)
EPA1	231858	3623260	3	1.46E-05	2.06E-04	30.5	45.7
EPA2	232192	3623550	3	N/A	3.73E-05	76.2	152.4
EPA3	232512	3623550	3	N/A	1.28E-05	91.4	167.6
EPA4	232398	3623550	3	N/A	2.69E-05	91.4	167.6
EPA5	232663	3623550	3	N/A	2.00E-05	83.8	198.1
EPA6	232292	3623550	3	N/A	6.93E-07	76.2	121.9
EPA7	232793	3623550	3	N/A	9.86E-06	76.2	350.5
EPA8	232824	3623980	3	N/A	6.61E-06	76.2	106.7
EPA9	231423	3623450	3	N/A	2.81E-06	53.3	53.3
EPA10	231422	3623240	3	N/A	1.27E-05	53.3	167.6
EPA11	231476	3623330	3	N/A	2.12E-06	320.0	167.6
EPA12	232028	3623230	3	N/A	2.81E-06	365.8	266.7
EPA13	232392	3623440	3	N/A	1.51E-05	160.0	53.34
EPA14	232492	3623250	3	N/A	9.20E-06	243.8	152.4
EPA15	232451	3623340	3	N/A	2.41E-05	30.5	30.48
EPA16	232453	3623250	3	N/A	1.97E-05	30.5	60.96
EPA17	231477	3623109	3	N/A	6.69E-06	330.0	122.0

Notes: N/A = Not Applicable

Table VII-4. Source Emissions and Parameters for Arizona Clean Fuels Volume Sources

Source ID	UTM Easting (m)	UTM Northing (m)	Release Height (m)	PM₁₀ (g/s)	VOC (g/s)	Lateral Dimension (m)	Vertical Dimension (m)
EP-V10	231449	3623324	7.3	N/A	8.73E-01	22.0	6.79
EP-V11	231636	3623414	7.3	N/A	7.59E-01	54.0	6.79
EP-V12	232211	3623363	7.3	N/A	5.50E+00	72.6	6.79
EP-Road1 through Road21	too many to list	too many to list	3.66	2.01E-03	N/A	9.6	3.4
EP-Road22 through Road71	too many to list	too many to list	3.66	2.01E-03	N/A	6.2	3.4

3. Modeling Results

The following sections present the results and conclusions from the air quality impact analyses. The air quality concentrations that are predicted by the dispersion models are compared to various “action thresholds,” including the Significant Impact levels (SILs), NAAQS, and PSD increments. Because the short-term NAAQS and PSD increments for all short-term averaging periods (1-hour through 24-hour averages) may be exceeded once per year, the dispersion models calculate both the highest (or “high-first-high”) and the “high-second-high” (“H2H”) short-term average concentrations. Given that the meteorological data used in the modeling analysis meet criteria established by the U.S. EPA to ensure a climatologically representative period (generally 5 years of National Weather Service data or 1 year of site-specific data), then the H2H concentration estimates are compared to the NAAQS and PSD increments. The meteorological data used in the Arizona Clean Fuels analysis did meet the U.S. EPA criteria, therefore the H2H concentration estimates were used in the NAAQS and PSD increment compliance analyses.

When determining if the proposed project exceeds the SILs, the highest modeled concentration must be used, and the extent of the Significant Impact Area (SIA) must be determined. This is because the “project only” modeling cannot determine how the ambient impacts from the proposed source overlap in time and space with other existing source impacts. Therefore, the only way to ensure that the proposed source impacts are insignificant at any potential modeled exceedance is to compare the highest modeled concentration to the SILs.

a. Class II Significant Impact Modeling and SIA

The results of the significant impact analysis (SIA) are shown in Table VII-5. The Permittee demonstrated that SO₂ and PM₁₀ emissions had predicted maximum concentrations greater than the significant impact level (SIL) for all applicable averaging periods, and the maximum radius of impact for any pollutant/averaging interval was determined to be 7.5 km. Consequently, a full impact analysis was required for SO₂ and PM₁₀.

Table VII-5. Maximum Air Quality Impacts from Arizona Clean Fuels Sources

Pollutant	Averaging Period	Maximum Project Impact^a ($\mu\text{g}/\text{m}^3$)	Significant Impact Level ($\mu\text{g}/\text{m}^3$)	Exceed SIL?
NO ₂	Annual	0.616 ^b	1	No
CO	1-hour	368	2000	No
	8-hour	170	500	No
SO ₂	3-hour	97.9	25	Yes
	24-hour	37.6	5	Yes
	Annual	2.35	1	Yes
PM ₁₀	24-hour	77.8	5	Yes
	Annual	1.39	1	Yes

^a High first high value

^b Value adjusted using the ambient ratio method (ARM)

b. Load-Screening Analysis

Three operating scenarios encompassing the anticipated range of normal operating conditions were modeled to determine worst case conditions. The three scenarios included the base case (100 percent capacity), the post maintenance outage case (95 percent capacity), and the reduced refinery throughput case (75 percent capacity). The results of the load screening analysis concluded that the base case, full capacity operation, was found to have the highest predicted impact on the ambient air for almost all criteria pollutant and averaging period combinations. Exceptions to this trend were determined for the 1-hour CO (maximum impact at 95 percent load), and annual average SO₂ concentration (maximum impact at 75 percent load).

c. Comparison of Arizona Clean Fuels Impacts with NAAQS and PSD Increments

The full impact analysis expanded the significant impact analysis by considering emissions from both the proposed project, as well as other sources in the SIA. Maximum modeled concentrations presented in the modeling report are presented in Table VII-6, and predicted ambient concentrations are compared to both the NAAQS and the Class II PSD increments. The NAAQS and PSD increment analyses were rerun by the Department using the corrected source and receptor grids data. The Department's revised NAAQS and PSD increment

results are presented in Table VII-6.

The Permittee's NAAQS analysis demonstrated that ambient impacts are predicted to be less than the NAAQS. This conclusion was reaffirmed in the Department's results from the revised modeling analysis.

The Permittee's analysis demonstrated that all ambient impacts were below PSD Class II increments.

Table VII-6. Permittee PSD Class II Increment and NAAQS Analysis

Pollutant	Averaging Period	Modeled Impact ^a (µg/m ³)	PSD Increment (µg/m ³)	Background Conc (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)	UTME (m)	UTMN (m)
SO ₂	3-hour	67.8	512	47.2	115.0	1300	232300	3624200
	24-hour	25.2	91	27.1	52.3	365	232360	3623989
	Annual	2.35	20	7.86	10.2	80	232310	3623990
PM ₁₀	24-hour	12.4	30	68.2	80.6	150	231872	3623063
	Annual	1.33	17	30.3	31.6	50	232260	3623991

^a Annual averaging period concentrations are high first high values; short term averages are high second high values

^b Value adjusted using ARM

d. AAAQGs Analysis

One of the programs used to control air toxics emissions in Arizona is the AAAQG program. AAAQGs are residential screening values that are protective of human health, but they are not regulatory air quality standards. Annual AAAQGs have been developed for human carcinogens, and assume an exposure frequency of 365 days per year for 70 years. Twenty-four hour AAAQGs also protect against excessive exposure to carcinogens. One-hour AAAQGs were developed with the intent to protect the more sensitive members of the population, including children and the elderly.

AAAQG pollutant emissions can be categorized as either process or fugitive. Several methods were used to calculate AAAQG pollutant concentrations depending upon the emission unit. These include (1) sources with known emission rates of specific pollutants (e.g., SRU hydrogen sulfide emissions), (2) area and volume sources of fugitive VOCs in which a representative speciated pollutant profile was applied (e.g, propane emissions from the Group B tanks), (3) sources

of inorganic pollutants which adhere onto particulate matter (e.g., crude unit and vacuum unit heater aluminum emissions) , and (4) combustion source speciated VOC emissions (e.g., crude unit and vacuum unit heater acetaldehyde emissions).

Only the following AAAQG pollutants were modeled as directly emitted from each source: benzene, chlorine, chlorobenzene, ammonia, MTBE, chromium (VI), nickel, hydrogen chloride, hydrogen sulfide, nitric oxide and tetrachlorethane. All other AAAQG pollutants were modeled by multiplying the constituent percentage of an emission stream (either VOC or particulate) by ambient impact of VOC or particulate, as applicable. For example, if aluminum was estimated to constitute 10 percent of particulate emissions from combustion sources, the model-predicted PM_{10} impact from combustion sources was multiplied by 0.10 to obtain the ambient impact of aluminum.

The Permittee used many conservative assumptions in estimating emissions of these pollutants. Many of the AAAQG emission rates are based upon representative source profiles obtained through EPA's FIRE database, the CATEF database, or EPA's SPECIATE source profile for petroleum refineries. For some pollutants, more than one database contained a value for an individual pollutant's percentage of VOCs, and these values often differed (see Table 7-28 in the Permittee's Air Quality Impact Analysis Report). The Permittee used a conservative approach by using the maximum percentage of any value found in the database.

Conservative assumptions were also used to quantify the ambient impacts from the AAAQG pollutants. In many cases, the highest constituent percentage listed in the SPECIATE database was multiplied by the maximum model-predicted VOC or PM_{10} concentration, as applicable, to estimate the maximum concentration of a given AAAQG pollutant. If AAAQG conformance is demonstrated using this methodology, no further analysis was necessary.

Modeling output files were reviewed to ensure correct emission rates and other model input parameters were entered correctly, and maximum model-predicted reported concentrations were supported by the model output.

The Permittee's modeling report did not include the AAAQG VOC and PM_{10} modeling files for the combustion sources, so the

Department conducted confirmatory modeling to determine the ambient concentration of VOC and PM₁₀ AAAQG pollutants. The maximum model-predicted impacts were then multiplied by the percent VOC or PM₁₀ content to obtain the pollutant-specific ambient impact. These values were then compared with the concentrations reported in the modeling report. In most cases, the concentrations were not equal, but in no case did the remodeled concentration exceed the AAAQGs.

Additionally, for pollutants whose maximum model-predicted impacts as presented in the Permittee's modeling report were within a factor of 10 of the AAAQG for any averaging period, additional steps were taken by the Department to verify conformance. These pollutants included aluminum, cadmium, lead, mercury, silver, selenium, chlorine, phenol, formaldehyde, hydrogen sulfide, ammonia, and benzene. Only formaldehyde was found to be underestimated, by a factor of 1.8. Consequently, the ambient concentration was increased by this factor, and conformance with the AAAQG was still demonstrated.

The Permittee's final modeling report presented HAP ambient impacts and comparisons to the AAAQGs. All reported concentrations were high-first-high maximum concentrations. Table VII-7 presents the Permittee's results of both short term and the annual AAAQG analyses for 45 pollutants analyzed. The Permittee's modeling indicates that maximum predicted annual ambient concentrations of benzene was greater than the AAAQG value. All other concentrations were estimated by the Permittee to be below the AAAQG levels.

Table VII-7. Arizona Clean Fuels Comparison to AAAQG for Compounds with Significant Emissions

Chemical	1-Hour Average		24-Hour Average		Annual Average	
	Modeled Concentration ($\mu\text{g}/\text{m}^3$)	AAAQG ($\mu\text{g}/\text{m}^3$)	Modeled Concentration ($\mu\text{g}/\text{m}^3$)	AAAQG ($\mu\text{g}/\text{m}^3$)	Modeled Concentration ($\mu\text{g}/\text{m}^3$)	AAAQG ($\mu\text{g}/\text{m}^3$)
Acetaldehyde	1.21E-01	6.30E+02	2.92E-02	1.70E+02	2.01E-03	4.50E-01
Aluminum	7.07E+01	4.50E+02	9.13E+00	1.20E+02	-	NL
Ammonia	2.49E+00	2.30E+02	4.97E-01	1.40E+02	-	NL
Antimony ⁴	6.02E-03	1.50E+01	7.78E-04	4.00E+00	-	NL
Barium	9.28E-01	1.50E+01	1.20E-01	4.00E+00	-	NL
Benzene ⁵	1.23E+02	1.70E+02	2.39E+01	4.40E+01	9.94E-01	1.40E-01
Benzo(a)pyrene	1.67E-04	6.70E-01	4.04E-05	1.80E-01	2.79E-06	4.80E-04
Cadmium	5.42E-02	7.70E-01	7.00E-03	2.00E-01	1.03E-04	5.60E-04
Chlorine	1.84E+01	2.50E+01	4.28E+00	1.20E+01	-	NL
Chlorobenzene	2.16E+00	1.10E+04	5.08E-07	2.80E+03	-	NL
Chromium	1.48E-02	1.50E+01	3.57E-03	4.00E+00	-	NL
Chromium (VI)	1.20E-03	1.70E-02	3.00E-05	4.40E-03	0.00E-05	1.20E-05
Cobalt	6.02E+00	NL (HAP)	7.78E-01	NL	1.14E-02	NL
Copper	1.09E-02	3.00E+00	2.64E-03	7.90E-01	1.82E-04	NL
Chrysene ¹	1.29E-04	NL	3.11E-05	NL	-	NL
Ethylbenzene	3.02E+01	4.50E+03	9.87E+00	3.50E+03	-	NL
Formaldehyde ⁶	7.00E-01	2.50E+01	1.69E-01	1.60E+01	1.17E-02	7.60E-02
Fluoranthene ¹	1.54E-03	NL	3.72E-04	NL	-	NL
n-Hexane	5.22E+01	5.40E+03	1.70E+01	1.40E+03	-	NL
Hydrogen Chloride	1.88E-01	2.10E+02	4.07E-02	5.60E+01	-	NL
Hydrogen Sulfide	8.46E+01	1.80E+02	7.09E+00	1.10E+02	-	NL
Iron	3.36E-00	1.50E+02	4.34E-01	4.00E+01	-	NL
Isopropylbenzene (cumene)	1.06E+00	HAP	3.47E-01	NL	2.05E-02	NL
Lead ²	2.23E-01	1.50E+00	2.88E-02	1.50E+00	4.23E-04	1.50E+00
Manganese	1.06E+00	2.50E+01	3.47E-01	7.90E+00	-	NL
Mercury	3.03E-01	1.50E+00	7.32E-02	4.00E-01	-	NL
Methyl t-butyl ether	3.41E+04	HAP	8.56E+03	NL	-	NL
Naphthalene	2.10E-02	6.30E+02	5.07E-03	4.00E+02	-	NL
Nickel	2.38E-03	4.50E-01	5.40E-04	1.20E-01	4.00E-05	2.10E-03
Nitric Oxide	3.18E+01	3.80E+02	7.34E+00	2.40E+02	-	NL
n-Octane	0.00E+00	1.50E+04	0.00E+00	1.20E+04	-	NL
n-Pentane	2.49E+01	1.90E+04	8.11E+00	1.40E+04	-	NL
Phenol	4.04E+01	3.20E+02	1.32E+01	1.50E+02	-	NL
Potassium ³	3.55E-01	NL	4.59E-02	NL	-	NL
Propane	4.29E-02	5.40E+04	1.04E-02	1.40E+04	-	NL
Selenium	1.68E-00	6.00E+00	2.17E-01	1.60E+00	-	NL
Silver	1.33E-01	3.00E-01	1.71E-02	7.90E-02	-	NL
Styrene	1.37E+02	3.50E+03	4.48E+01	1.70E+03	-	NL
Sulfur ³	6.06E+01	NL	7.82E+00	NL	-	NL
Tetrachloroethene	1.70E+00	1.30E+03	3.69E-01	6.40E+02	2.82E-02	1.70E+00
Toluene	7.52E+00	4.40E+03	2.46E+00	3.00E+03	-	NL
Trimethylbenzene	8.18E+01	1.40E+03	3.09E+01	9.90E+02	-	NL

Table VII-7. Arizona Clean Fuels Comparison to AAAQG for Compounds with Significant Emissions

Chemical	1-Hour Average		24-Hour Average		Annual Average	
	Modeled Concentration ($\mu\text{g}/\text{m}^3$)	AAAQG ($\mu\text{g}/\text{m}^3$)	Modeled Concentration ($\mu\text{g}/\text{m}^3$)	AAAQG ($\mu\text{g}/\text{m}^3$)	Modeled Concentration ($\mu\text{g}/\text{m}^3$)	AAAQG ($\mu\text{g}/\text{m}^3$)
(1,3,5-)						
Trimethylbenzene (1,2,4-)	2.51E+01	1.40E+03	8.18E+00	9.90E+02	-	NL
Trimethylpentane (2,2,4-)	2.31E+01	HAP	2.26E+01	NL	-	NL
Xylenes (total)	4.56E+00	5.40E+03	1.49E+010	3.50E+03	-	NL
Zirconium	2.29E-01	8.30E+01	2.96E-02	4.00E+01	-	NL

NL = No Listed Guideline

Bolded values are greater than the applicable AAAQG guideline.

- 1 – No individual guideline concentrations are provided for these chemicals, however, they are included as polycyclic organic matter.
- 2 – The AAAQG concentration listed is the NAAQS, which is a quarterly average. The quarterly averaged concentration would be significantly lower than the short term averages reported.
- 3 – These chemicals are included in the AAAQG list, however, no guideline concentrations are provided.
- 4 – The model predicted impact shown in the modeling report is not supported as the emission rate of antimony is shown to be zero; consequently, the ambient impact should be zero as well.
- 5 – Benzene concentrations shown in this table are not supported by findings during the Department’s review. Then annual benzene impact was remodeled as discussed below. Revised annual benzene concentrations decreased from $0.994 \mu\text{g}/\text{m}^3$ to $0.13 \mu\text{g}/\text{m}^3$.
- 6 – Ambient impacts of formaldehyde shown here should be multiplied by a factor of 1.8.

Benzene:

The Permittee’s modeling report showed that the predicted benzene concentration would exceed the annual AAAQG value of $0.14 \mu\text{g}/\text{m}^3$ in the area beyond the process area boundary and beyond the property boundary. The Department’s review of this analysis identified several errors and discrepancies that were corrected and changed by the Department before performing confirmatory modeling. These corrections and changes are as follows:

- 1) The Permittee’s benzene emission rates for the Group B storage tanks and the tank farm thermal oxidizer stack (EP-16) were incorrect, apparently because the Permittee’s contractor did not properly portray the venting configuration. For 240 hours each year, the thermal oxidizer does not operate. During this period, the subject benzene stream is vented to a co-located stack with no controls. Consequently, a new stack was added (EP-16r) with the same stack height as EP-16. The stack gas exit temperature was assumed to be 100°F ; the gas was assumed to exit at 1 m/sec, and the stack gas exit diameter

was assumed to be 1 m.

For the short-term impact analysis, the emissions from the thermal oxidizer (EP-16) were “turned off” during this venting scenario as the uncontrolled emissions are mutually exclusive. The collocated stack (EP-16r) was modeled with uncontrolled benzene emissions of 0.28 lb/hr during this alternative operating scenario. During normal operations, EP-16 was modeled with a short-term benzene emission rate of 0.0055 lb/hr.

For the annual impact analysis, the emissions from the thermal oxidizer (EP-16) were modeled at the normal emission rate for 8,520 hours/yr (i.e., “turned off” for 240 hours/yr). The modeled annual benzene emission rates were 0.023 tons/yr for EP-16 and the 0.033 tpy for EP-16r.

2) EP-V10 was deleted, as these benzene emissions will occur through EP-16r as described above, and the emissions are not properly characterized as a volume source.

3) For each of the loading rack thermal oxidizers (EP-17 and EP-27), the short-term benzene emission rate is 0.0199 lb/hr, and the long-term benzene emission rate is 0.0065 tons/yr. These values are considerably lower than what was shown in the Permittee’s modeling report.

4) Long-term benzene emissions from EP-V11 are 0.088 tons/yr, reflecting the correction described in item (1) above.

5) Benzene emissions from EP-V12 were changed to 0.125 lb/hr short-term and 0.367 tpy long-term, reflecting the correction described in item (1) above.

7) For all sources of fugitive benzene emissions due to equipment leaks, the Permittee’s analysis did not take into account several VOC BACT provisions that arose after submittal of the modeling report. These provisions, most importantly the limits on percent leaking components, were incorporated into the Department’s analysis.

The Department revised the benzene impact analysis based upon these comments and reran the analyses. The revised model-predicted impacts for the annual benzene concentration decreased from 0.994 $\mu\text{g}/\text{m}^3$ to 0.13 $\mu\text{g}/\text{m}^3$.

B. Additional Impacts Analysis

1. Growth Analysis

The growth analysis is performed to assess the impacts due to additional growth resulting from project, but not directly emitted from the project. The assessment is performed to ensure compliance with NAAQS and PSD increments. The Permittee performed a qualitative analysis of the impacts due to growth. A quantitative analysis was not performed due to the many uncertainties.

The Permittee proposes that more than 500 plant employees in three shifts will be needed for operation of the new facility. The Permittee anticipates that these employees will be drawn primarily from the existing population of Yuma. Additionally, the applicant anticipates that there would be some industrial and economic growth, promoted by the refinery, in the area surrounding the refinery.

Predicted increases in air emissions from this population influx are primarily a result of the increase in vehicle exhaust from the increase in traffic flow. An incremental increase in vehicle traffic in the area is expected to occur due to employee and product delivery travel. The projected increase in traffic levels, and subsequent impact on local air quality, have not been quantified as part of the submitted permit application, but it is unlikely that the air quality impacts from the vehicular traffic will change any of the air quality analysis conclusions. Therefore, the Department has concluded that a detailed growth analysis is not warranted.

2. Effects on Soils and Vegetation

A.A.C. R18-2-407.I.1 requires that the PSD permit application include an analysis of the impacts that emissions from the proposed facility and from secondary growth will have on soils and vegetation. The Permittee was unable to identify any specific sensitive soil and vegetation resources in the project vicinity through consultation with the Arizona Department of Game and Fish and the United States Fish and Wildlife Service. A comparison of the maximum predicted concentrations to the screening levels found in the U.S. EPA document, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (U.S. EPA 1980), none of the screening levels are exceeded. Therefore, the results indicate that the project will not adversely impact soils and vegetation in the area.

3. Visibility Impacts Analysis

A.A.C. R18-2-407.I.1 and R18-2-410 require that the PSD permit application include an analysis of the impacts that emissions from the proposed major

source and from secondary growth will have on visibility. This requirement is separate from the required Class I visibility impact analysis. The visibility analysis was conducted for one sensitive Class II wilderness area: the Muggins Mountains, located 32 km northwest of the proposed refinery. This analysis was performed using the VISCREEN model with maximum hourly emission rate inputs for directly emitted PM₁₀, NO_x, directly emitted NO₂. Emission rates of elemental carbon and directly emitted sulfate were assumed to be negligibly small.

For purposes of the Permittee’s VISCREEN analysis, all project sources were assumed to contribute to a single plume. In reality, this assumption is likely to be conservative (i.e., over-predict plume visibility). Under certain combinations of stability class and wind speed, plumes emitted at different heights and with different dispersion characteristics (e.g., exhaust exit velocity, building or stack-tip induced downwash, and exhaust temperature) will not necessarily merge into a single coherent plume.

The Permittee’s modeling report demonstrated that its impact would exceed the Class I visibility screening thresholds in the Muggin Mountains Class II Wilderness Area. The revised VISCREEN modeling results are shown in Table VII-8.

Table VII-8. Level II VISCREEN Analysis Inputs and Results

Input Emission Rates								
PM			5.00 g/s					
NO _x (as NO ₂)			6.69 g/s					
Primary NO ₂			1.14 g/s					
Soot			0.00 g/s					
Primary SO ₄			0.00 g/s					
Transport Scenario Specifications								
Background Ozone			0.08 ppm					
Background Visual Range			218 km					
Source-Observer Distance			32 km					
Minimum Source-Class I Distance			32 km					
Maximum Source-Class I Distance			40 km					
Plume-Source-Observer Angle			11.25 degrees					
Stability Class			F					
Wind Speed			2.5 m/s					
Maximum Visual Impacts Inside Muggins Mountain Class II Wilderness Area								
					<u>Delta E</u>		<u>Contrast</u>	
Background	Theta	Azimut	Distanc	Alpha	Criteria	Plume	Criteria	Plume
SKY	10	133	40	36	2	1.968	0.05	0.04
SKY	140	133	40	36	2	0.646	0.05	-0.016
TERRAIN	10	84	32	84	2	4.892	0.05	0.032

TERRAIN	140	84	32	84	2	0.235	0.05	0.003
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C. Class I Area Impacts Analysis

The Permittee has not performed a detailed analysis of Class I area impacts for the proposed Mohawk project site, which is located 191 km from the nearest Class I area, Joshua Tree National Park. The previous Class I area analysis demonstrated impacts below levels of concern when the project was originally proposed near Mobile, Arizona, only 88 km from the nearest Class I area (Superstition Wilderness). The Department considers the prior analysis for the Mobile site to provide adequate demonstration that the proposed project, located at the Mohawk site, will not cause or contribute to unacceptable impacts at any Class I area.

D. Conclusions

The Permittee has adequately demonstrated that the proposed project will not cause or contribute to an exceedance of any NAAQS or PSD increment, will conform with all AAAQGs, and will not cause any unacceptable adverse impacts on soils, vegetation, or visibility.

VIII. INSIGNIFICANT ACTIVITIES

The following is a list of general activities that may occur at the proposed facility which fall under the definition of “Insignificant Activities” pursuant to A.A.C. R18-2-101(57), or “Trivial Activities” pursuant to A.A.C. R18-2-101(117).

- A. Landscaping, building maintenance, or janitorial activities (R18-2-101(57)(a)).
- B. Manually-operated equipment used for buffing, carving, cutting, drilling, machining, routing, sanding, sawing, surface grinding or turning and associated venting hoods (R18-2-101(57)(f)).
- C. Chemical Laboratories including lab equipment used exclusively for chemical and physical analysis (R18-2-101(57)(i)).
- D. Fuel burning equipment rated at less than 0.5 MMBtu/hr (R18-2-302(B)(2)(b)(v)). Such equipment includes gas-fired space heaters, hot water heaters, and process boilers. Specific equipment, model numbers, maximum potential heat rates, and site locations are not available at the present time (R18-2-101(57)(j)).
- E. Additional Insignificant Sources. The following is a listing of additional equipment or activities which the Department has determined to be insignificant.
 - 1. Petroleum product storage tanks and associated loading operations for lubricating oil, transformer oil, and used oil (R18-2-101(57)(j)).
 - 2. Piping of fuel oils, used oil and transformer oil (R18-2-101(57)(j)).
 - 3. Storage and handling of drums or other transportable containers where the containers are sealed during storage, and covered during loading and unloading (R18-2-101(57)(j)).
 - 4. Water and Wastewater Treatment (R18-2-101(57)(j)):
 - a. Water treatment or storage systems for boiler feedwater.
 - b. Water treatment or storage or cooling systems for process water.
 - c. Chemical storage associated with water and wastewater treatment where the water is treated for consumption or is used within the permitted facility.
 - 5. Individual flanges, valves, pump seals, pressure relief valves, and other individual components not in VOC, organic HAP, or H₂S service (R18-2-101(57)(j)).
 - 6. Cafeterias, kitchens, and other facilities used for food or beverage preparation. (R18-2-101(117)(d)).
 - 7. Equipment using water, water and soap or detergent, or a suspension of abrasives in water for purposes of cleaning or finishing.
 - 8. Battery recharging areas (R18-2-101(117)(r)).
 - 9. Aerosol can usage (R18-2-101(57)(j)).
 - 10. Acetylene, butane, and propane torches (R18-2-101(57)(j)).
 - 11. Equipment used for portable steam cleaning. (R18-2-101(117)(xx)).
 - 12. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system or collector serving them exclusively (R18-2-101(57)(j)).
 - 13. Lubricating system reservoirs (R18-2-101(57)(j)).
 - 14. Hydraulic system reservoirs (R18-2-101(57)(j)).
 - 15. Adhesive use (R18-2-101(57)(j)).

16. Production of hot/chilled water for onsite use (R18-2-101(57)(j)).
17. Safety devices such as fire extinguishers (R18-2-101(57)(j)).
18. General vehicle maintenance and servicing activities (R18-2-101(57)(j)).
19. Storage cabinets for flammable products (R18-2-101(57)(j)).
20. Office/Administration:
 - a. Housekeeping activities and associated products for cleaning purposes and operation of vacuum cleaning systems (R18-2-101(57)(j)).
 - b. Air conditioning, cooling, heating or ventilation equipment (R18-2-101(117)(b) and (c)).
 - c. General office activities such as paper shredding, copying, photographic activities, and blueprinting (R18-2-101(57)(j)).
 - d. Restroom facilities and associated cleanup operations, stacks, and vents (R18-2-101(117)(h)).
 - e. Smoking rooms and areas (R18-2-101(117)(j)).
 - f. Normal consumer use of consumer products, including hazardous substances as defined in the Federal Hazardous Substances Act (15 U.S.C. 1261 et. seq.) (R18-2-101(57)(j)).
21. Firefighting activities and training conducted at the facility in preparation of fighting fires. The various components of this fire fighting system include (R18-2-101(57)(j)):
 - a. Foam System Fire Water Systems
 - b. Dry Chemical Extinguisher
22. Rail car traffic and locomotive switching activities (R18-2-101(57)(j)).

IX. ABBREVIATIONS AND ACRONYMS

AAAQG	Arizona Ambient Air Quality Guideline
A.A.C.	Arizona Administrative Code
Arizona Clean Fuels	Arizona Clean Fuels
ADEQ	Arizona Department of Environmental Quality
ADEQ MG	Arizona Department of Environmental Quality Modeling Guidelines
AGO	Atmospheric Gas Oil
ANSI	American National Standards Institute
API	American Petroleum Institute
AQRV	Air Quality Related Value
ARM	Ambient Ratio Method
ASME	American Society of Mechanical Engineers
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
BLM	Bureau of Land Management
Btu	British Thermal Unit
Btu/scf	British Thermal Unit per Standard Cubic Foot
°C	Degrees Celsius
CAM	Compliance Assurance Monitoring
CARB	California Air Resources Board
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
DAF	Dissolved Air Flotation
DEM	ERL-Athens Dynamic Estuary Model
dscf/MMBtu	Dry Standard Cubic Feet per Million British Thermal Unit
°F	Degrees Fahrenheit
FLAG	Air Quality Related Values Workgroup
FLM	Federal Land Manager
FR	Federal Register
GAQM	Guideline on Air Quality Models
GEP	Good Engineering Practice
gr/dscf	Grains per Dry Standard Cubic Foot
g/s	Gram per Second
HAP	Hazardous Air Pollutant
HF	Hydrogen Fluoride
H ₂ S	Hydrogen Sulfide
HHV	Higher Heating Value
HON	Hazardous Organic NESHAP
HVGO	Heavy Vacuum Gas Oil
ISC	Industrial Source Complex
ISCST3	Industrial Source Complex 3 Short Term Model
IWAQM	Interagency Workgroup on Air Quality Modeling
K	Kelvin

kg/ha-yr	Kilograms per Hectare per Year
km	Kilometers
kPa	Kilopascals
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/hr	Pound per Hour
lb/MMBtu	Pound per Million British Thermal Unit
LDAR	Leak Detection and Repair
LPG	Liquified Petroleum Gas
LVGO	Light Vacuum Gas Oil
m	Meter
MDEA	Methyl Diethanolamine
$\mu\text{g}/\text{m}^3$	Microgram per Cubic Meter
MMBtu	Million British Thermal Unit
MMBtu/hr	Million British Thermal Unit per Hour
mmHg	Millimeters of Mercury
m/s	Meter per Second
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standard
O_2	Oxygen (Molecular)
O_3	Ozone
OAQPS	Office of Air Quality Planning and Standards
OSBL	Outside Battery Limits
OSHA	Occupational Safety and Health Administration
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 Microns
ppm	Parts per Million
ppmv	Parts per Million by Volume
ppmvd	Part per Million by Volume, Dry Basis
ppmw	Parts per Million by Weight
PSA	Pressure-Swing Adsorption
PSD	Prevention of Significant Deterioration
psia	Pressure per Square Inch Absolute
psig	Pressure per Square Inch Gauge
PSM	Process Safety Management
RACT	Reasonable Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RFG	Refinery Fuel Gas
ROI	Radius of Impact

RON	Research Octane Number
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SIA	Significant Impact Area
SIC	Standard Industrial Code
SIL	Significant Impact Level
SNCR	Selective Non-Catalytic Reduction
SO ₂	Sulfur Dioxide
SO _x	Sulfur Oxides
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SRP	Sulfur Recovery Plant
SRU	Sulfur Recovery Unit
SWS	Sour Water Stripper
TGTU	Tail Gas Treatment Unit
TNRCC	Texas Natural Resources Conservation Commission
TOC	Total Organic Compounds
UAM	Urban Airshed Model
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
UTME	UTM Easting
UTMN	UTM Northing
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquid
WWTP	Wastewater Treatment Plant

X. AMBIENT AIR QUALITY MONITORING

In response to concerns expressed during the public comment period for Permit Number 1001205 with respect to the proposed refinery's HAP emissions, the Department has included additional ambient air quality monitoring requirements to the refinery's air permit. These additional requirements are set forth in Section XXX of Attachment "B" to the permit. Specifically, in addition to the ambient monitoring network required for hydrogen sulfide under Section XXIV of Attachment "B," the permit now requires that the Permittee install, maintain, and operate ambient monitoring networks for particulate matter and benzene. These pollutants were selected by the Department because they represent the pollutants of primary concern.

Both the particulate matter and benzene monitoring networks are required to be installed and operating for at least one year prior to the beginning of on-site construction and related activities. Monitoring for particulate matter will continue for the duration of the on-site construction activities; monitoring for benzene will continue for the life of the source. For each monitoring network, the permit requires that the Permittee submit to the Department a monitoring plan for the Department's approval. The monitoring plans will establish the number, type, and location of monitors or sampling stations and, in the case of the benzene monitoring system, the means that the refinery will use to disseminate ambient air quality information to the general public. The Department envisions that this will involve the use of the World Wide Web.