OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **February 5, 2018**

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THROUGH: PM Phil Martin, P.E., Manager, Existing Source Permits Section

THROUGH: AT Amalia Talty, P.E., Existing Source Permits Section

FROM: DSS David Schutz, P.E., New Source Permit Section

SUBJECT: Evaluation of Permit Application No. **2012-1062-C (M-10)(PSD)**
HollyFrontier Tulsa Refining LLC (Formerly Holly Refining & Marketing)
Expansion of Tulsa Refinery (SIC 2911)
East Refinery (FAC ID 1458)
902 W. 25th Street, Tulsa, Tulsa County (36.126°N, 96.002°W)
Portions of Sections 13, 14 and 23, T19N, R12E

I. INTRODUCTION

HollyFrontier Tulsa Refining (Holly) has requested a modification to their PSD construction permit, Permit No. 2012-1062-C (M-8)(PSD) issued January 8, 2016. A heater designated 1H-101 in EUG-27 serving the Distillate Hydrotreating Unit (DHTU) was previously stated as having a capacity of 55 MMBTUH, but the firing rate is being corrected to 80 MMBTUH. Although the heater is not being physically modified, the different capacity will impact previous PSD permit analyses including emissions changes and ambient impacts. The heat input of 80 MMBTUH will be stated as a permit limit with compliance based on a 12-month rolling average. Additionally, the emissions from the sulfur recover unit (SRU-2) have been updated to reflect the results of the stack test plus a safety factor and modeling changes were incorporated to reflect the reduction in FCCU heater stack height.

HollyFrontier Tulsa Refining LLC (HFTR) and Holly Energy Partners (HEP) operate the Tulsa Refinery and product loading terminal under three separate permits. The two refineries owned by HFTR were acquired at separate times, therefore, are permitted separately. The loading terminal is owned and operated by HEP, resulting in another separate permit for it. However, the two refineries and loading terminal are interconnected and collocated, requiring that they be treated as a single facility when conducting a PSD analysis. For the purpose of the PSD analysis only, HFTR and HEP together are at times referred to as "Holly."

The proposed changes to the two PSD permits (the West Refinery and the East Refinery) are evaluated in the following updated PSD analysis.

In 2014, HFTR and HEP proposed a construction project to expand the refineries and loading terminals. The project commenced in the 2015 time frame. There will be new process units added and modification of existing process units such that the total capacities of the refineries will be increased to 170,000 BPD from 160,000 BPD. There will be "associated" emissions increases from most units in the refinery, excepting those emissions units which are independent of unit process rates such as emergency engines, fugitive VOC leakage from valves, flanges, etc. The net emissions change analysis applies to all three, and all PSD analyses other than BACT will encompass all three facilities. The BACT analysis in this permit will be limited to the types of units being added to the East Refinery.

HFTR has also applied for a modified PSD construction permit for the West Refinery. That application includes the following items:

- The MEK Unit itself has fugitive VOC leakage components in EUG-7. The fugitive component counts are being updated from the previous permit. The "MEK Unit" uses methyl ethyl ketone to extract wax from paraffins from the Lube Extraction Unit (LEU). Since the unit was considered "modified" previously, making it subject to NSPS Subpart GGGa, the counts update is not a "modification" in the context of NSPS but does change emission rates.

- The external shell of the Crude Distillation Unit (CDU) will be repaired. The permit application is treating this repair project as a "life extension" project subject to PSD permitting analyses. The primary effect of this change is moving the fugitive components from EUG-7 to EUG-8; all other changes in throughputs and emissions are part of the overall project to expand the refineries.

- The HFTR-West Refinery Asphalt Truck Loading Dock has four bays. Since about 1992, only one bay has been needed; the other three have been out of service. One of the out of service bays has been reactivated, and an additional loading bay was installed in August 2016. The re-activated and new bays allow East Refinery VTB and PDA to be sent to the Coker. The resulting emissions have been added to EUG 32.

Over the previous 5 years, there have been multiple construction projects which were subject either to PSD review or to requirements to keep records of actual emissions to show that the difference between Baseline Actual Emissions and Actual Emissions did not exceed PSD levels of significance. Those permits will be superseded by this construction permit, incorporating those preceding changes as part of the "net emissions changes" in the PSD netting analysis.

The overall project is subject to Prevention of Significant Deterioration (PSD) review for added emissions of greenhouse gases (GHG), carbon monoxide (CO), nitrogen oxides (NO_X), and particulate matter (PM_{10} / $PM_{2.5}$). Full PSD review consists of:

A. determination of best available control technology (BACT)
B. evaluation of existing air quality and determination of monitoring requirements
C. evaluation of PSD increment consumption
D. analysis of compliance with National Ambient Air Quality Standards (NAAQS)

E. ambient air monitoring
F. evaluation of source-related impacts on growth, soils, vegetation, visibility
G. evaluation of Class I area impacts.

The refinery will accept NSPS Subpart Ja limits on SO_2 emissions on all fuel gas combustion devices to net out from PSD for SO_2. The Projected Actual Emissions from selected, existing fuel gas combustion devices were based on 25 ppm H_2S in refinery fuel gas. Reductions required for netting have been added to the East Refinery construction permit.

II. FACILITY DESCRIPTION

The East Refinery is a fuels refinery with several major process units. Other activities include various minor processes outside the major units, including storage and transfer of products. Much of the equipment was placed in service before the promulgation of permitting requirements. The oldest construction dates from approximately 1907, when the Texas Company commenced building in the area. Sinclair purchased the facility from Texaco in 1983, and then HFTR purchased the refinery in 2009. Refinery property covers approximately 470 acres.

Refining is a complex process to make crude oil into a variety of products, including gasoline, heating oil, lubricants, and feedstocks for other industries. Refining equipment and processes involve a certain amount of iterative treatment, in which materials may be processed more than once at a particular location or may be returned to an earlier step in the system for further handling. Only those processes necessary to understand the basic principles are presented.

A very general description of the entire process at this particular refinery starts with crude oil being processed in the Crude Unit. Process streams flow from the Crude Unit to the Fluid Catalytic Cracking Unit (FCCU), the Distillate Hydrotreating Unit (DHTU), Naphtha Hydrodesulfurization Unit (NHDS), and the Unifiner/Penex (Penex). A residual stream currently becomes asphalt or residual fuel oil; in the near future, that residual stream is planned to be processed for extraction of gas oil and asphaltene feedstocks. Tulsa Refinery primary products are classified as gasoline, distillate, residual fuel oil, and asphalt, but there are also ancillary products, such as propane, butane, propylene, and sulfur.

Note that Emission Unit Groups (EUGs) are based on different criteria from those used to describe process units, so descriptions of the EUGs do not match those of the processing units. For example, EUG #9 consists of heaters found in three different units. Similarly, the storage tanks are divided into EUGs based on roof design and permit status.

A. Crude Distillation Unit (CDU)

Distillation is a thermal process that separates product fractions out of a mix of materials based on differences in boiling points. The CDU separates crude oil into intermediate products, which are either feedstocks for downstream units or residual products. Sour crude, defined by HFTR as crude oil with sulfur content greater than 0.5% by weight, represents approximately 10% of all volume processed by this unit. The remaining 90% sweet crude at the Tulsa refinery has historically averaged approximately 0.4% by weight sulfur.

Crude oil is currently brought to the refinery by pipeline. Sweet and sour crude are segregated in storage tanks and are processed in separate batches through the CDU. All crude is de-salted before entering the distillation towers to remove chlorides that would be damaging to piping and vessels. Sweet crude is usually injected into sour crude runs. There are fugitive emissions from the CDU. The only point source is a common stack serving two heaters. These gas-fired heaters serve the atmospheric distillation tower and the vacuum distillation tower (EUG 9, Point ID 6155). Crude flows through the atmospheric tower first, where the lighter ends are removed or distilled. "Atmospheric" simply refers to the fact that the constituents distilled in the tower are capable of vaporizing at atmospheric pressure. Heavier ends that are not distilled in this tower are then run through the vacuum tower for further separation. A vacuum is achieved in the vacuum tower through use of three stages of steam ejectors. Condensers remove condensable vapors to the greatest extent possible after each of the ejectors. The vent gas flows to the wet gas compressor (J-50) within the FCCU or into the flare system if J-50 is not operating. Some material is refluxed, meaning that it is taken out of the column and reintroduced at an earlier point to achieve better separation into distinct product fractions. Refluxing is also a method for taking heat out of the tower. It is one of the processes that is used at different points and that constitutes one of the techniques to improve performance and more efficiently process materials in the CDU. The proposed project involves modification of the CDU Atmospheric Tower Heater from 200 to 248 MMBTUH capacity which will allow throughput to increase from 63,000 BPD to 70,000 BPD.

HFTR defines eight outputs from the CDU in order of increasing molecular weight as follows. Numbers 1 - 6 come from the atmospheric tower, while 7 and 8 come from the vacuum tower.

1. Light ends. This stream is methane and ethane and goes to the FCCU wet gas scrubber.
2. Butane/propane. This stream goes to the DHTU.
3. Light straight run. This is mostly C_5 material and goes to Penex.
4. Naphtha. This material goes to the NHDS.
5. Kerosene. This goes to the DHTU.
6. Light atmospheric gas oil. This goes to the DHTU.
7. Gas oils. These go to the FCCU.
8. Vacuum resid. This is the residual material or "bottoms" remaining after all other outputs have been captured. Resid currently goes directly for sale as asphalt or roofing flux. (There are no asphalt blowstills or other oxidation processes utilized at the Tulsa Refinery.) Part of the expansion is installation of "ROSE" Unit to process resid into asphaltenes and "gas oil" feed to the FCCU.

The facility refers to the sour bottoms as asphalt and to all other material as "flux." Intermediate storage for both materials is in heated tanks.

Personnel operating the CDU are also responsible for managing butane truck loading and unloading (EU 22, Point ID 6171).

B. Fluid Catalytic Cracking Unit (FCCU)

The FCCU treats gas oils from the CDU with heat in the presence of a catalyst. Generally, hot gas oil from sweet crudes is mixed with cold gas oil from sour crudes, and the situation is reversed when sour crude is being processed. The FCCU has current capacity estimated at 24,000 BPD with a maximum anticipated processing rate of 28,400 BPD. "Gas oils" are heavier than diesel and lighter than the residual products taken from the CDU. Heavy molecules are broken or "cracked" into lighter molecules that allow the facility to increase the production of liquid fuels. A distillation tower then separates these products into gasoline and diesel components, as well as producing feedstock for the Alkylation (ALKY) and Scanfiner (SCAN) Units.

FCCU catalyst is regenerated continuously to prevent coke build-up, with sufficient catalyst added daily to maintain a relatively constant inventory and level of catalytic activity. Spent catalyst is removed from the regenerator every few days and stored for sale to other refiners or catalyst brokers. This catalyst is valuable and various devices control potential air emissions of it, to minimize its loss. The first set of these devices consists of cyclones in the reaction vessel. In addition, the regenerator contains five three-stage cyclones. The electrostatic precipitator (ESP) on the FCCU stack has been replaced by a wet gas scrubber (WGS). Salts and particulates removed by the WGS are shipped offsite for disposal, while the liquid will be sent to the oily wastewater collection system. A selective catalytic reduction (SCR) system has been added to control NO_X emissions. Installation of the SCR required the addition of a 20,000-gallon tank for aqueous ammonia and two 6,400-gallon tanks for sodium hydroxide. The aqueous ammonia is an ammonium hydroxide solution with less than 20% concentration of ammonia. Carbon monoxide emissions from the regenerator are minimized through complete combustion by controlling the excess oxygen content in the flue gas. The FCCU is very difficult to shut down and start up due to the high temperatures involved and the volume of catalyst circulating through it. These activities are managed and tracked through the facility's startup, shutdown, and malfunction plan (SSMP).

Similar to the handling of crude in the CDU, products of this cracking process are distilled thermally in the tower. Heavy ends, or tower "bottoms," are known as decanted oil. Light ends from this unit and gasses from the CDU are compressed and run through an absorber at the FCCU. Any remaining gas becomes part of the refinery fuel gas system. A set of electrically-driven compressors is used to compress and circulate the unit gas for further processing. These compressors are often called the "wet gas compressors."

A gas-fired charge heater (B-2) supplies heat for current operation of the FCCU. Heat to perform the function of this reboiler is now taken from the fractionator slurry bottoms. A gas-fired air heater (B-1) is used only during FCCU startup. A gas-fired steam superheater has been idle since 1996. Heat previously supplied by the superheater is now obtained from B-2.

Propylene loading of railcars (3-spot) and trucks (1-spot) is functionally connected to the FCCU. Additionally, the FCCU is responsible for the operation of two flares, all pressurized spheres, and all pressurized "bullet" tanks except for three tanks located at the ALKY Unit. The CDU, FCCU, ALKY, POLY, and PENEX Units feed flare #1. Everything else is directed to Flare #2. During normal refinery operation, both flares feed into a common header and are directed to the flare gas recovery unit.

Part of the expansion project is improvement to the FCCU, replacing the reactor, riser, and feed nozzles with modern designs. Modern equipment is expected to maximize product yield and reduce coke generation, the source of air emissions. Despite the increased throughput, emissions are not projected to increase.

C. Unifiner/Penex Unit (PENEX)
PENEX is a process that was installed at the ISOM (Isomerization) Unit in 2002. The ISOM was commissioned in 1987 by modifying a catalytic reforming unit (CRU) that had been idle for a long period. The PENEX upgrades the octane of light straight run naphtha from the CDU by isomerizing the normal pentanes to isopentanes. The PENEX also saturates benzene, thus reducing the benzene and aromatic levels in gasoline produced by HFTR. Light straight run naphtha from the CDU is sent to intermediate storage before it is charged to the PENEX. PENEX contains two reactors that can be operated independently. Catalyst in these reactors has an optimal life of seven years and is reclaimed, but not regenerated. The charge is first treated by the Unifiner reactor to remove sulfur and nitrogen. This is a catalytic process that requires hydrogen from the CCR (see below) to combine with the elemental sulfur stripped out of various compounds, such as mercaptans. The hydrogen sulfide thus formed can be stripped out of the stream and sent for processing at the SRU (see below). Unifiner catalyst is long-lived and normally does not require regeneration.

Products from the PENEX are normally sent to intermediate storage as gasoline blending components but can also be blended directly into gasoline. Offgas produced is run through an absorption process before being sent to the fuel gas system. The absorber is light cycle oil from the FCCU. Heavier constituents of the offgas are absorbed by the oil and sent to the FCCU fractionator, while the lighter ends are used as fuel gas. The Unifiner section has a charge heater and stack (EUG 9, Point ID 6167). The normal charge rate to the PENEX is approximately 6,000 BPD although it has nominal capacity to charge over 8,500 BPD.

D. Continuous Catalytic Reforming Unit (CCR)
The CCR upgrades the octane of heavy straight run naphtha from the CDU (through the NHDS) by dehydrogenating the hydrocarbons, resulting in the production of high octane materials such as aromatics. These high octane "blend stocks" are blended directly into gasoline. This stream is one of the most important components of premium grades of gasoline. HFTR's reforming process is also called "platforming," because it uses a platinum catalyst in three reactors. The catalyst is fouled quickly by sulfur, so only sweet naphtha feedstock from the NHDS may be used. This process had been performed by the catalytic reforming unit (CRU), which was modified under Permit No. 98-021-C (M-26) to create the CCR. The existing unit was converted into a CCR capable of processing approximately 22,000 BPD of desulfurized naphtha from the NHDS. Three new reactors hold approximately 100 tons of catalyst and circulate 1,000 pounds

of catalyst through the regenerator per hour. Catalyst flows down through each reactor, dropping from each reactor to the next. As the catalyst exits the bottom of the third reactor, a countercurrent flow of hydrogen purges hydrocarbon back into the third reactor. Nitrogen then carries the catalyst to filter media at the top of the regenerator structure, where fines are removed from the catalyst before it flows to a disengaging hopper.

The "disengaging" term used here means that this is the point at which the catalyst is no longer borne by the nitrogen; it is "disengaged" or separated from the nitrogen transportation medium. Approximately 5-10 pounds of fines are expected to be removed daily and sent for offsite reclamation. The catalyst is cooled to 250-300°F in the disengaging hopper, and is then dropped into the regenerator. The regenerator has three zones, identified as the diluted air zone, the oxychlorination zone, and the drying zone. Approximately 0.07 mol% oxygen is reacted with the catalyst to begin coke burn-off in the diluted air zone. The low oxygen content and the name of the zone are derived from diluting air with nitrogen. The catalyst then drops to the oxychlorination zone, where it is reacted with air and perchloroethylene (perc), which conditions the catalyst by redistributing the metal on the catalyst. Air is blown across the catalyst in the drying zone to remove any remaining moisture. The regenerated catalyst exits the bottom of the regenerator and is moved with hydrogen to the reduction zone above the top of the first reactor. At this point it is further regenerated by contact with additional hydrogen, which combines with excess oxygen to create water vapor. During reactor operation, chloride is injected into the reactor to help maintain catalyst activity. The regenerator tower vents back through the disengaging hopper, allowing the sulfur and chloride in the regenerator vent gas to be absorbed by the catalyst entering the regenerator. This reabsorption process is known as Chlorisorb. Platforming produces hydrogen that is then used by the NHDS, DHTU, SCAN, and PENEX units for desulfurization of their feedstocks, although some of the hydrogen is retained or recycled in the reactors to prevent the reaction from cracking the naphtha. The CCR had first operations on December 11, 2007.

There are five heaters associated with this unit. A 155 MMBTUH heater, identified as the #1 Interheater (10H-113), is described in EUG 26. One stack serves the 101 MMBTUH Interheater #2-1, the 25 MMBTUH Interheater #2-2, and the 120 MMBTUH charge heater, and is identified as Point ID 6163 in EUG 27. The 85 MMBTUH stabilizer reboiler heater is identified as Point ID 6162 of EUG 27. The newer 155 MMBTUH heater was installed with low-NO_X burners and the 120 and 85 MMBTUH heaters have been retrofitted with low-NO_X equipment.

Part of the proposed expansion project is installing an additional 25 MMBTUH heater at the CCR Unit.

E. Naphtha Hydrodesulfurizer Unit (NHDS)

The NHDS removes sulfur from the CCR charge (heavy straight run naphtha). The sulfur removal process is catalytic and requires hydrogen, which is supplied by the CCR. The interdependence of this unit and the CCR requires that sufficient sweet material produced by the NHDS be stored to provide for a startup of the CCR. Sulfur is removed in the form of H_2S. Most of the offgas from this unit is recycled, with excess gas being amine-treated before going to the fuel gas system. Hydrogen is injected in several places and a large part of the unit has two-phase flow. Some of the hydrogen passes through the system and is being continually recovered, compressed, and recycled. The NHDS is normally shut down every three to four years for maintenance, based on catalyst life. The catalyst is not normally regenerated and is replaced every few years. Spent catalyst is sent off site for either regeneration or metals reclamation and disposal. This unit had first operations on March 20, 2006. A pre-modification capacity of 22,000 BPD was stated for this unit.

There are two heaters with low-NO_X burners at this unit. A 39 MMBTUH charge heater and a 44.2 MMBTUH stripper reboiler heater are both described in EUG 25. Part of the proposed expansion is installing an additional 10 MMBTUH heater at the NHDS Unit.

F. Distillate Hydrotreating Unit (DHTU)

The old naphtha/distillate HTU was converted to a DHTU capable of processing approximately 24,000 barrels per day (BPD) in 2006. Conversion included new internals in the reactor, such as reducing the number of catalyst beds, using a new catalyst, and redesigning the quench nozzles. There are several new vessels, including a high pressure separator, a new amine treater, a coalescer, a salt tower, and various air and water coolers. The existing HTU charge heater remains in service as the DHTU charge heater, but the stripper reboiler heater was permanently removed in 2006. First operations at the DHTU occurred May 25, 2006. The refinery interconnection increased the capacity to 40,000 BPD, and the proposed project will further increase capacity to approximately 45,000 BPD.

The DHTU removes sulfur from diesel blend stocks. Both #1 and #2 diesel streams are treated in the DHTU. Naphtha is treated by the NHDS (see E above). The DHTU normally treats distillate streams from the field or hot from the CDU or the FCCU. Gases from this unit are treated before going to the fuel gas system. The DHTU is normally shut down every three to four years for maintenance, based on catalyst life. The catalyst is not normally regenerated and is replaced every few years. The catalyst is sent off site for either regeneration or metals reclamation and disposal. The DHTU is dependent on the CCR for hydrogen. The DHTU is also responsible for the Light Hydrocarbon Treating Unit (LHC) which treats light hydrocarbon streams to remove hydrogen sulfide.

There are currently two emission points associated with this unit; one active and one inactive. The charge heater stack is Point 6157 in EUG 27. The other stack is Point ID 6156 (was in EUG 9) common for both the splitter and fractionator reboiler heaters, both of which were idled as part of the conversion of the old HTU to the DHTU. Part of the proposed expansion is installing an additional 50 MMBTUH heater at the DHTU Unit.

G. Alkylation Unit (ALKY)

Alkylation is a process that creates large molecules by reacting two shorter molecules in the presence of a catalyst. In this case, the alkylate produced is typically high-octane material necessary for blend stock. Debutanizer net overhead from the FCCU is rich in butenes and serves as ALKY feedstock. The feed is pre-treated by the POLY. Treated feed first passes through a deethanizer. Light ends are sent to the fuel gas system and the feed is sent to the propylene splitter at the POLY unit, as described in Item "H" following. The remaining olefin feed, consisting mostly of butenes, is returned to ALKY to be reacted with isobutanes using sulfuric acid as a catalyst to produce the alkylate. The process uses isobutanes greatly in excess of the stoichiometric amount, so the alkylate is fed through three more towers, those being the depropanizer, deisobutanizer and debutanizer. Historically, approximately 3,500 BPD of alkylate has been produced. The facility accepted a limit of 5,500 BPD to avoid PSD consideration under Permit No. 98-021-C, issued October 18, 2000; that limit is being relaxed to 6,500 BPD in this permit. The ALKY receives sulfuric acid and stores it for use. It also sends spent acid for regeneration. Sulfuric acid is loaded from and unloaded to trailers at the ALKY, and can also be received from and loaded into rail cars. ALKY personnel are also responsible for three pressurized bullet tanks, Nos. 58, 59, and 60, located on the unit (EUG 22, Point ID 6288 through 6290). One of these tanks holds butane, a second holds isobutane, and the third is a surge tank used for emergency service. There are no point sources associated with this unit.

H. Poly Pretreat Unit (POLY)

This area of the refinery was originally a polymerization unit, hence the name POLY. Most of the unit has been idle since some time prior to HFTR's purchase of the refinery, but some pieces of equipment have been used for other purposes. Feed for the ALKY unit is treated by the POLY to remove sulfur and any other impurities that might harm the catalyst or otherwise disturb the reaction. An amine system removes hydrogen sulfide, caustic solution removes residual hydrogen sulfide and mercaptan sulfur, and a water wash removes basic nitrogen compounds. A propene recovery system, often referred to as the propylene splitter, was started at the POLY unit in 1996. Approximately 600 BPD of propene have been recovered, stored, and sold as a product in the past. POLY is estimated to have average capacity of 4,000 BPD. There are no point sources associated with this unit.

I. Scanfiner (SCAN)

The SCAN process takes all or a portion of naphtha (often referred to as "cat naphtha" or "cat gasoline") from the fluid catalytic cracking unit (FCCU) and removes the sulfur. The first stage of the process, the diolefin saturator, is designed to convert diolefins into olefins without beginning hydrodesulfurization or olefin saturation. Diolefins need to be removed as they can cause significant fouling in the process equipment.

After diolefin saturation, the cat naphtha is fed into the main SCAN reactor, where hydrodesulfurization, hydrodenitrogenation, and olefin saturation reactions occur over a catalyst. The main product from this reactor is low sulfur cat naphtha, which is a key blend component in producing low sulfur gasoline blends. The process consumes hydrogen and also recovers hydrogen, hydrogen sulfide, and ammonia. The product stream is cooled and water washed prior to entering the reactor effluent separator. Water wash helps prevent chloride build-up in the equipment, and the water is reused to the greatest extent possible through the system. A minimal amount of water is sent to the refinery wastewater system to maintain wash water quality. The hydrogen from the reactor effluent separator, called recycle gas, is sent to an amine absorber in the SCAN unit where the hydrogen sulfide is removed. A small portion of the recycle gas is purged to the fuel gas system to maintain adequate hydrogen purity and makeup hydrogen is fed into the recycle gas upstream of the amine absorber. The recycle gas is then compressed and sent back to the reactor section. Liquid hydrocarbon from the separator is sent to the product stripper, where light ends (butane and higher) and hydrogen sulfide are removed. The non-condensable gas stream (hydrogen, hydrogen sulfide, ammonia) from the separator is sent to an existing amine absorber where it is amine scrubbed for hydrogen sulfide removal prior to injection into the fuel gas system. Low sulfur gasoline from the product stripper is sent to gasoline blending after cooling. ARU (Amine Regeneration Unit) #1 processes the sour amine solution from the amine absorber. Acid gas from the ARU is vented to the sulfur recovery units (SRU#1 and/or SRU#2).

The hydrogen utilized in the SCAN process is obtained from the excess hydrogen produced by other process equipment. This hydrogen would otherwise be blended into the refinery fuel gas system and used to fire the various process heaters and boilers at the refinery. While the SCAN process generates a small quantity of fuel gas, any additional fuel gas demand at the refinery created by removal of the hydrogen from the fuel gas system is satisfied by purchasing natural gas. First operations of the Scanfiner unit occurred December 17, 2004.

J. Sulfur Recovery Units (SRU #1/ SRU #2)

The SRUs recover sulfur from acid gas streams and sour water stripper overhead and store it in elemental form for sale. The refinery currently has an amine system that removes H_2S from various gas and liquid hydrocarbon streams. There are six amine treaters (or "contactors") that contact the different streams with lean amine, where "lean" means that the amine has a low concentration of H_2S. The lean amine absorbs the H_2S, making it into a "rich," or high-concentration, stream. The ARU regenerates the amine solution by boiling it, producing lean amine to return to the contactors and hydrogen sulfide to feed the SRU. The SRUs use the Claus process. One third of the H_2S is oxidized to form SO_2 and the SO_2 is reacted with the remaining H_2S in the presence of an alumina catalyst to form elemental sulfur and water vapor. The liquid sulfur is stored in a pit for shipping by rail or truck. The reaction does not achieve total removal of sulfur (manufacturer's guarantee is 99.5%) so the tail gas is scrubbed by Tail Gas Treating Units (TGTU) to recover most remaining sulfur oxides formed before they are released from the stack (EUG 10, Point ID 6152). The TGTUs incinerate remaining H_2S to SO_2, which is then removed by a following caustic scrubber. Scrubber waste products are routed to the wastewater treatment system. Tail gas concentration of SO_2 is maintained below 250 ppm on a 12-hour rolling average. Continuous emission monitors (CEMs) on both SRUs demonstrate compliance. SRU #2 had first operation on June 1, 2006.

The Sour Water Stripper (SWS) is also associated with this complex of units. The SWS takes sour water from various units and removes ammonia and H_2S. Modifications to the SWS in 2006 replaced the trays, increased the operating pressure of the stripper, and installed a new feed-to-bottoms heat exchanger. These changes increased the capacity to approximately 190 gpm. Offgas from SWS is sent to SRU #2, because SRU #1 has proven incapable of handling this material without fouling of the catalyst. If SRU #2 is unavailable for some reason, SWS will be placed on fresh water feed or shut down and sour water stored in tanks. Upon return to service of SRU #2, any accumulated sour water will be processed and the offgas sent to SRU #2.

The design capacities of SRU #1 and SRU #2 are each 25 long tons per day (LTPD).

K. ROSE Unit

A new ROSE Unit will be constructed at the East Refinery. Residuum Oil Supercritical Extraction (ROSE) is a process where a light, condensable hydrocarbon such as liquid propane or isobutene is used to treat the "residuum oil," or bottoms from the vacuum distillation unit. Residuum contains a mixture of heavy oils from which FCCU feed ("gas oil") can be separated from asphaltenes. The process mixes the light hydrocarbon with the residuum, extracting the gas oil from the asphaltenes. Asphaltenes are processed off-site to produce road and roofing asphalt, and the light hydrocarbon is evaporated out from the gas oil. The light hydrocarbons are condensed back to liquids then recycled to the process.

L. Boiler House (BOHO)

The BOHO is responsible for steam production for the refinery. The BOHO is also responsible for the other utility systems such as plant air, instrument air, and nitrogen. There are four existing boilers at the BOHO, each capable of producing over 100,000 pounds per hour of 250 psig steam. These boilers primarily burn sweet plant fuel gas. Although each boiler is also capable of burning liquid fuel, the piping to facilitate liquid fuel burning has been removed. Generally, a different boiler is shut down every six months for maintenance. The Consent Decree (Case No. 2:08-cv-0020-WFD) (CD) required that each boiler have its own stack and that each boiler be subject to NO_X control. Now there are selective catalytic reduction (SCR) systems on all four boilers. Continuous emission monitoring systems (CEMS) have been installed on each stack. These are the only emission points associated with the BOHO.

M. Wastewater Treatment Plant (WWTP)

The Wastewater Treatment System collects and treats wastewater generated in the refinery prior to discharging water to the Arkansas River, including both process generated wastewater and storm water. Both federal and state agencies regulate the effluent going to the river. Federal requirements are under the jurisdiction of the Environmental Protection Agency (EPA) and are covered by the National Pollutant Discharge Elimination System (NPDES). State requirements are under the jurisdiction of the Oklahoma Department of Environmental Quality (ODEQ) and are covered by the Oklahoma State Discharge Permit System (OSDPS). Various federal standards govern wastewater operations, including 40 CFR 60 (NSPS) Subpart QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems), 40 CFR 61 (NESHAP) Subpart FF (Benzene Waste Operations NESHAP [BWON]), and 40 CFR 63 (MACT) Subpart CC (Petroleum Refineries).

There are five sewer systems, three of which handle oily (process) wastewater and two of which handle (non-process) storm water. Storm water systems are not subject to NSPS Subpart QQQ. Each of the five systems is described as follows.

- Uncontrolled refinery individual drain system (IDS) and uncontrolled API separator tanks.
- IDS and API separator tank(s) controlled by BWON. The IDS and API tank(s) were installed in 2005.
- Refinery slop oil system, in which tankage is designed with BWON-compliant controls.
- A storm water collection system that ties into the first common junction box of the uncontrolled refinery IDS. This system collects storm water from concrete pads and areas within unit limits (on-unit).
- A storm sewer system that collects storm water from outside the process unit battery limits (off-unit) and routes it to the off-unit storm pond. The pond holds approximately 33 million gallons of this water that is normally used for cooling tower makeup water, although it can be discharged to the Arkansas River.

HFTR currently purchases approximately 3 million gallons of additional municipal water daily to make up for process use.

The first four systems are all routed to the WWTP. Water entering the WWTP is tested for various impurities at the diversion box. Material with certain levels of impurities is sent to the off-test tank, from which it is later blended back into the treatment system. The water then passes through either of two API separators, with any skimmed hydrocarbon going to a slop oil tank. Water continues to the equalization basin, where it is stirred and aerated and microbial action begins to digest the hydrocarbons. A bio-disk unit continues the digestion process with more "bugs." Clarifiers separate the dead microorganisms and any other solids from the water for further processing in a digester. Upgrades to the aeration basin and clarifiers were made in 2001 and 2003. Biological material wasted from this process is used as fertilizer to maintain vegetative cover on the facility's two closed land treatment units. Remaining water goes to the Final Pond, where it is tested before discharging to the Arkansas River or being used to irrigate the refinery's two closed land treatment units. A large pond and two tanks are available as storage for rain that falls on the process units. Tank 477 with a nominal capacity of 5,031 bbls was constructed in conjunction with Permit No. 98-021-AD (M-37) and acts a wide spot in the line to slow storm surge flow from the NHDS and SRU#2 units. On-unit storm water from tank 477 travels through an uncontrolled IDS and then through tank 476 to the equalization basin. Tank 459 with a nominal capacity of 80,000 bbls has been repurposed from EUG 1 (MACT CC Group 1 Storage Vessels) to storm water surge storage as described in Permit Nos. 98-021-TV (M-50) and 2007-005-AD (M-4). Storm water can be pumped from the on-unit storm water pond to tank 459 and back again as needed for containment. Various water treating chemicals including hydrogen peroxide are used in treating wastewater. Fugitive emissions from the Wastewater Treatment System are included with Equipment Leaks - Process Units.

N. Miscellaneous Points
Miscellaneous equipment leaks or fugitive emissions occur from all piping components throughout the refinery. These emissions are estimated with AP-42 factors and there are two points associated with fugitive emissions. The Hydrocarbon Recovery System consists of an ongoing effort to recover oil from beneath the refinery. It consists of several wells, separators, and storage tanks or batteries scattered throughout the refinery. This equipment is moved as necessary to maximize the recovery of oil. The hydrocarbon recovery system has small emissions, but cannot qualify as an insignificant activity because it is subject to 40 CFR 63 Subpart GGGGG (EUG 18). There are several cooling towers that serve the refinery. The cooling towers are treated using sodium hypochlorite.

A fuel system using light ends from various processes to feed combustion devices is known as the refinery fuel gas system and the rich gas it carries is frequently called RFG. Fugitive emissions from the RFG system are calculated and listed with other fugitives from each unit.

As noted in the introduction, oldest parts of the facility date from 1907. Some of the equipment at the facility was constructed before state or federal air pollution rules and regulations were promulgated, and many of these sources are grandfathered (exempt from permit requirements). DEQ or a predecessor agency has permitted various pieces of equipment. A list of those permits was contained in the memorandum associated with the initial TV permit. Other environmental permits include RCRA Post Closure for the Flare Area Treatment Unit (EPA No. 990750960-PC) and NPDES wastewater discharge (EPA No. OK0001309 / DEQ No. I72001630).

III. PROPOSED PROJECT DESCRIPTIONS

The proposed projects for each facility are listed following. The new and modified units are categorized as combustion units (heaters); process units with fugitive VOC leakage from valves, flanges, etc.; the Fluid Catalytic Cracking Unit (FCCU); the Continuous Catalyst Regenerator serving the Platformer Unit; and storage tanks.

East Refinery
- A new Naphtha Splitter Heater (H-205, 100 MMBTUH) will replace the existing Naphtha Splitter Heater (75 MMBTUH).
- A new 10,000 BPCD Liquid Petroleum Gas (LPG) Recovery Unit charging 32 MMSCFD gas;
- A new 10,000 BPCD Residuum Oil Supercritical Extraction (ROSE) Unit with a new 42 MMBTUH HHV heater;
- Expanded Diesel Hydrotreater Unit (DHTU), with a new 50 MMBTUH HHV helper heater;
- Revamped FCCU, increasing process throughput from 24,000 BPCD to capacity of approximately 28,400 BPCD;
- Modified Naphtha Hydrodesulfurizer (NHDS) Unit, with a new 10 MMBTUH HHV helper heater;
- Modified Continuous Catalytic Reforming (CCR) Unit, with a new 25 MMBTUH HHV helper heater;
- A new Naphtha Fractionation Column which will require steam from facility boilers;
- Expansion of the Alkylation (ALKY) Unit to 6,500 BPD, using steam from existing boilers for process heat.